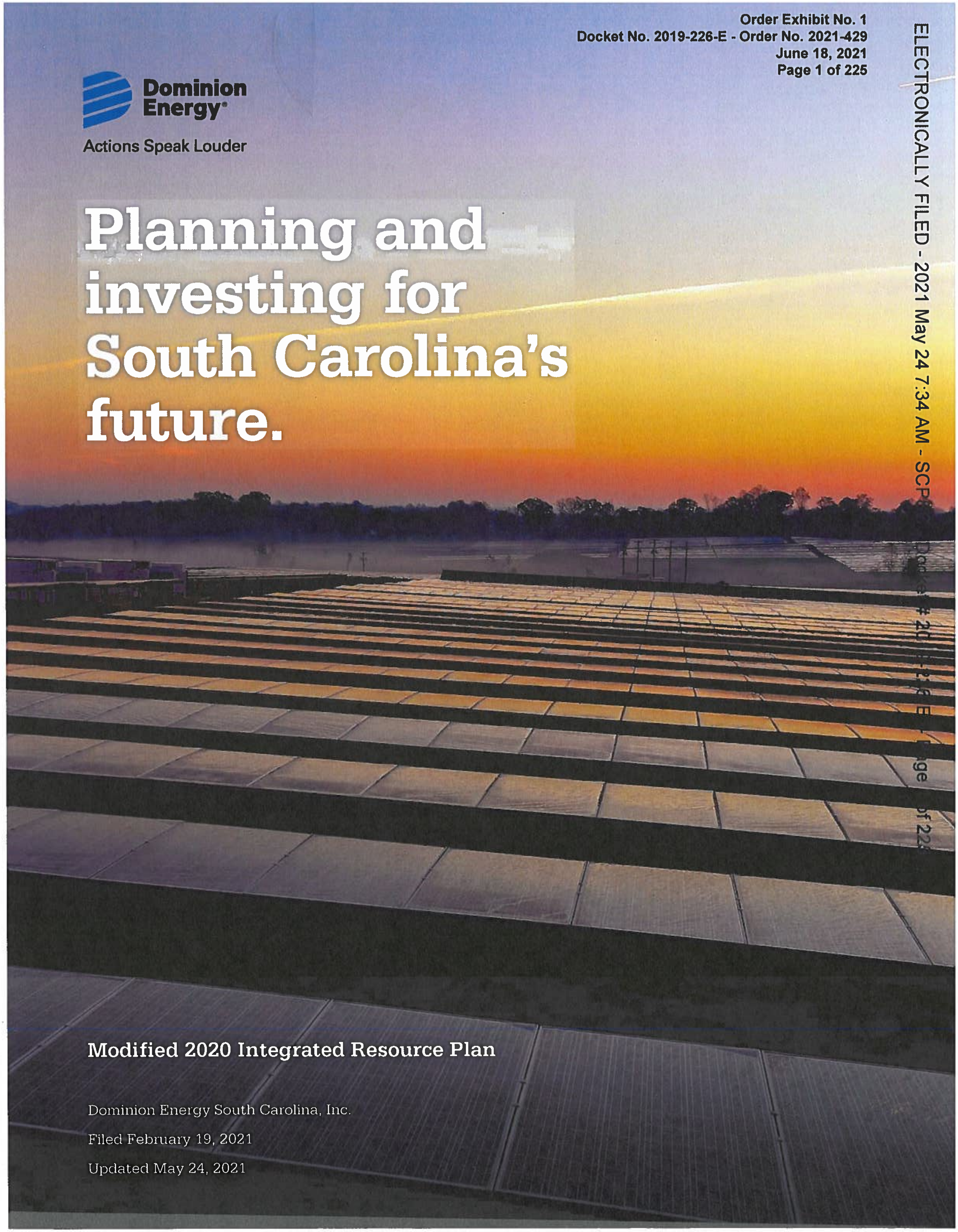

Dominion Energy®

Actions Speak Louder

Planning and investing for South Carolina's future.

Modified 2020 Integrated Resource Plan

Dominion Energy South Carolina, Inc.

Filed February 19, 2021

Updated May 24, 2021

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Our Company

Table of Contents

South Carolina's state flower: Yellow Jessamine.

Dominion Energy

Our Company

Table of Contents

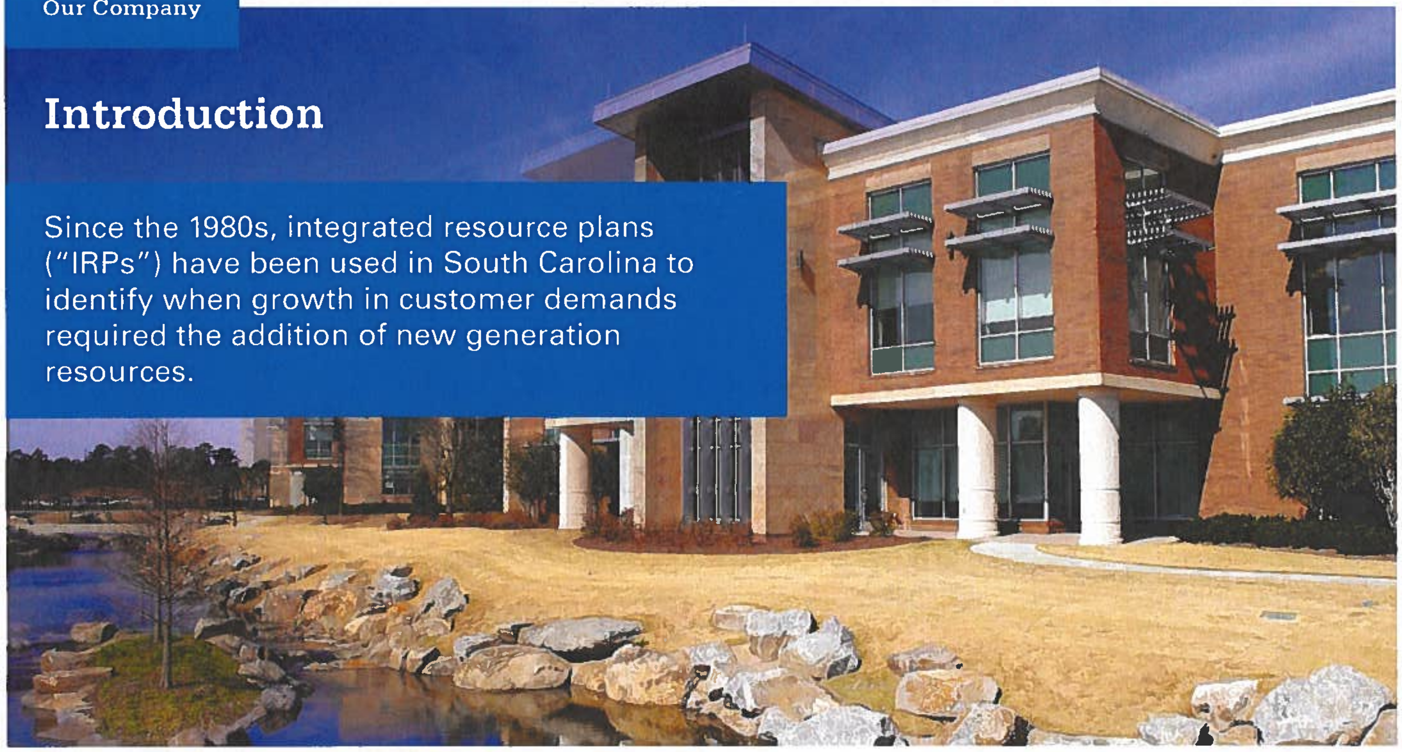
Intake towers at Lake Murray.

Dominion Energy

Our Company

Introduction

Since the 1980s, integrated resource plans ("IRPs") have been used in South Carolina to identify when growth in customer demands required the addition of new generation resources.



Dominion Energy South Carolina corporate campus.

Introduction

Since the 1980s, integrated resource plans ("IRPs") have been used in South Carolina to identify when growth in customer demands required the addition of new generation resources and to identify what generating technologies would be most cost effective in meeting those demands. In past years, IRP evaluations involved relatively few variables. The determinative factors were the forecasted rate of demand growth, the price and availability of fossil fuels, and the relative capital cost and efficiency of traditional fossil or nuclear generating facilities.

In recent years, the focus of the IRP process has shifted to reflect growing societal demands for cleaner energy and greater energy conservation. This demand for cleaner energy has led to the rapid development and deployment of renewable generation assets and storage technologies. This has been accompanied by dramatic reductions in the cost and increases in the range of options for these technologies. Increasingly stringent environmental regulations have also caused smaller coal units to be retired and have created additional uncertainty about continued reliance on coal generation generally.

On the demand side, prioritizing clean energy has increased the emphasis and investment in demand side management ("DSM') and energy efficiency ("EE") programs to as a way to limit demand and consumption. At the same time, a combination of technological developments and federal and state mandates have driven dramatic efficiency improvements in lighting, appliances, machinery and building construction. These efficiency gains have fundamentally affected load growth forecasts.

Over the course of the next decade, the societal trends driving the creation of a more efficient and cleaner energy economy are anticipated to continue and accelerate. Meeting the challenges posed by these trends and ensuring reliability as increasing volumes of intermittent solar generation come on line has made the IRP process more complex. These trends have added many more variables and possible outcomes. As a result, the IRP process has become much more important to Dominion Energy South Carolina, Inc. ("DESC" or "Company"), its customers and the State of South Carolina.

In keeping with these trends, in 2019, the South Carolina General Assembly revised the IRP statute ("Revised IRP Statute") through the enactment of Act No. 62. Under the Revised IRP Statute that Act No. 62 created, IRPs must evaluate an extensive list of topics and sensitivities related to load forecasts, generation technologies, renewable resources, DSM and EE programs, generator retirements, fuel costs, environmental regulations and electric transmission plans. This Revised IRP Statute

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established factors that the Public Service Commission of South Carolina (the "Commission") must balance in approving a resource plan including resource adequacy, affordability and least cost to customers, environmental compliance, reliability, exposure to commodity price risk, and supply diversity. The Revised IRP Statute requires utilities to evaluate multiple resource plans that can provide reliable service to customers while including a mix of new generation technologies, retirements of existing units, and other factors. DESC's 2020 IRP was the first IRP filed under the Revised IRP Statute.

This Modified 2020 IRP is filed with the Commission in accordance with S.C. Code Ann. § 58-37-40 (2019) and Order No. 98-502. It also satisfies the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-430 (2015). It presents potential plans for meeting the energy and capacity needs of its customers over the years 2020 through 2034 and measures the outcomes generated by those plans over the period 2020-2059. **Appendix A** cross references the sections of this Modified 2020 IRP to the operative South Carolina statutes governing the contents of an IRP, establishing that all statutorily required elements of an IRP are addressed.

In addition, on December 23, 2020, the Commission issued Order No. 2020-832 in Docket No. 2019-226-E finding that the IRP previously filed should be re-filed as modified within sixty days. **Appendix B** cross references the sections of this Modified 2020 IRP to the requirements of Order No. 2020-832, establishing that elements of the Modified 2020 IRP required by Order No. 2020-832 are addressed.

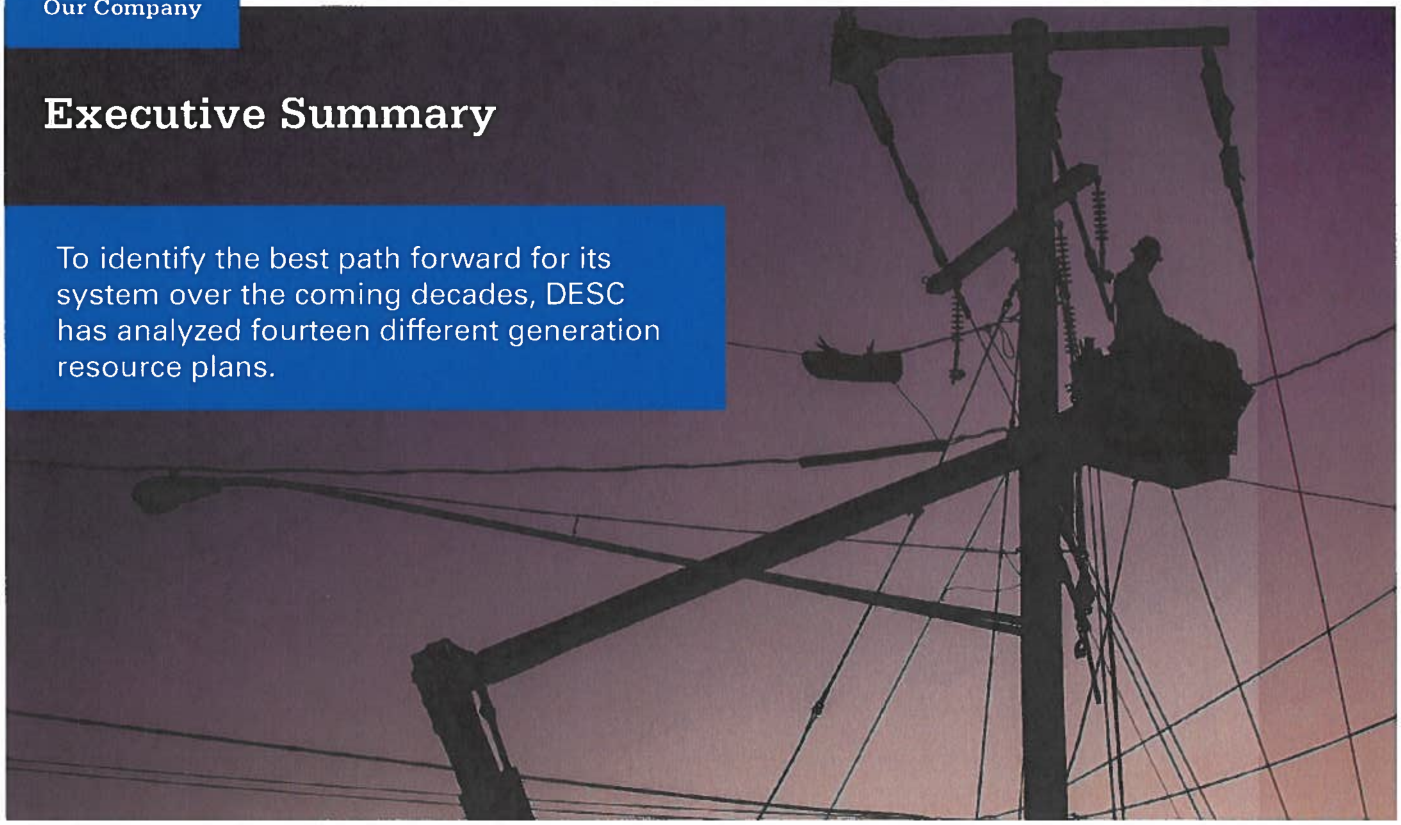
Given the pace of change in customer expectations, technological advances, and environmental policies, it is important that the Company remain flexible with respect to resource plans and asset procurement. Resource plans will be updated to reflect current needs and information when future procurement or retirement decisions are considered based in them. The fact that DESC has modeled the procurement or retirement of any resource in this Modified 2020 IRP does not mean that DESC has made the decision to procure or retire that resource. These decisions will be made based on the facts and analysis available at the time they are made.

Dominion Energy

Our Company

Executive Summary

To identify the best path forward for its system over the coming decades, DESC has analyzed fourteen different generation resource plans.



Dominion Energy lineman ensuring reliable service.

Executive Summary

Throughout its history, the Company has been dedicated to the delivery of safe, reliable and affordable energy to its customers. This dedication has included a strong movement towards a clean environment. For example, since 2002, DESC has closed eight of its twelve coal units or repowered them with natural gas and reduced the percentage of coal-based energy used to serve customers from 69% in 2005 to 23% in 2019. Since 2005, DESC's carbon emissions have dropped by 42%, sulfur dioxide emissions by 99%, nitrous oxide emissions by 84% and mercury emissions by 85%.

Over the past five years, the Company has become a leading solar utility in the Southeast. It has added nearly 1,100 MW of utility scale and customer scale solar generation capacity to its system and now has approximately 67% more nameplate solar capacity than nuclear capacity. In 2019, DESC embarked on a program to implement advanced metering infrastructure ("AMI") which improves customer service, increases efficiency, and supports new demand reduction and energy conservation programs. In that same year, DESC committed to a plan to more than double its spending on energy efficiency and demand side management programs with particular emphasis on reaching low income communities and small businesses located in them.

The Company has now entered a new phase in its overall efforts to preserve the environment. On February 11, 2020, the Company's parent company – Dominion Energy – announced a significant expansion of its greenhouse gas emissions reduction goals, establishing a new company-wide commitment to achieve net zero carbon dioxide and methane emissions by 2050. Net zero does not mean eliminating all emissions, but instead means that any remaining emissions of CO_2 or methane are balanced by removing an equivalent amount from the atmosphere. This strengthened commitment builds upon Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions. The commitment is also a recognition of the increased expectations and interest among customers, policy makers, and employees in building a clean energy future.

This Modified 2020 IRP presents alternative plans to put the Company on a trajectory to continue building a cleaner, more efficient, and lower carbon emitting utility, while balancing customer affordability, system reliability, and generation diversity. To identify the best path forward for

Dominion Energy

Our Company

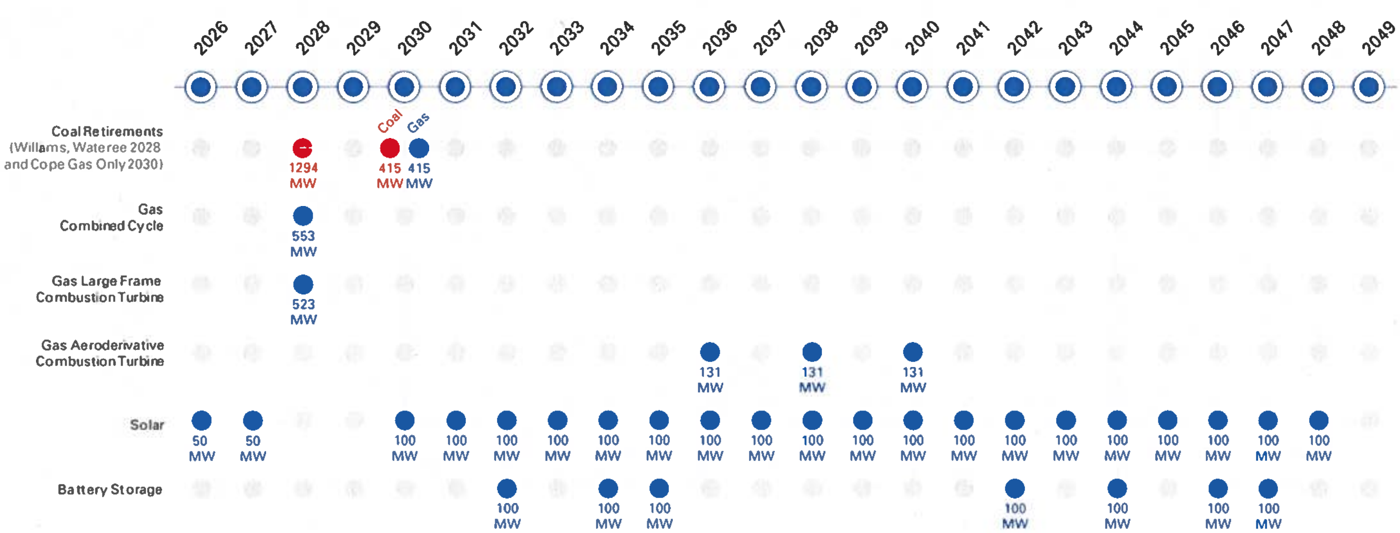
Executive Summary

the system over the coming decades, DESC has analyzed fourteen different generation resource plans. They assume the deployment of different combinations of new solar resources, new storage resources, new natural gas resources and existing generating resources. Three of the plans assume the early retirement of existing coal or fossil-steam units.

DESC has tested these resource plans against 27 price and demand scenarios using a broad variety of evaluation metrics addressing specific criterion enumerated in the Revised IRP Statute. Those metrics are tied to cost effectiveness, carbon reduction, renewable generation utilization, fuel price resiliency, reliability and supply diversity. The 27 scenarios include three sets of natural gas price forecasts, three assumptions concerning future CO_2 emissions costs and three DSM cases. In all, 378 individual scenarios (14 resource plans x 27 forecasts) have been modeled over a 40-year planning horizon. In addition, this Modified 2020 IRP addresses each of the items specified in Order No. 2020-832. It incorporates the changes in assumptions, forecasts and sensitivities required under that order and provides the systematic and quantitative evaluations required by that Order.

In this evaluation, Resource Plan 8 ("RP8"), which retires large coal plants before the end of the decade and adds substantive amounts of solar and batteries, had the highest score across the vast majority of the metrics.

Resource Additions under Resource Plan 8 by Year



Dominion Energy

Our Company

Executive Summary

RP8 assumes that the three coal-fired units at Wateree and Williams Stations are retired in 2028. The sole remaining coal plant, Cope Station, is converted to natural gas only in 2030. The missing Williams and Wateree coal capacity is replaced with a new high-efficiency, low-emitting combined cycle natural gas unit and several large-frame natural gas internal combustion turbine ("ICT") units. This replacement generation protects reliability and provides a base of dispatchable generation to support the addition of 1,900 to 2,000 megawatts ("MW") of solar and 700 to 900 MW of battery storage from 2026 to 2048. Reliability would be supported by also adding quick-start aeroderivative ICTs as needed. This plan creates a diverse and reliable portfolio of both renewable and dispatchable resources while providing a significant reduction in CO_2 emissions and a large increase in clean energy generation.

RP8 Results: Retire Williams and Wateree in 2028, convert Cope to gas fired only in 2030 and add renewables and storage

Evaluation Metric	Ranking out of 14 Resource Plans Across 27 Sensitives
40 Year Levelized Cost Net Present Value	1
2049 CO_2 (Tons Emitted)	1
2049 Clean Energy (MWh)	1
Average Fuel Costs	11
Generation Diversity	1
Reliability	1
Mini-Max Regret	1
Cost Range	1

Retirement of traditional generation and the addition of large quantities of solar capacity, which is intermittent and non dispatchable, pose reliability challenges. To maintain reliability while retiring coal generation, RP8 increases system reliance on natural gas relatively quickly compared to other resource plans (although all resource plans envision this switch happening by the end of the planning horizon). This increased use of natural gas will require an increase in the capacity of the natural gas pipelines that deliver gas into South Carolina, which is limited today. The costs and reliability impacts of the coal plant retirements that RP8 envisions are yet to be fully quantified through station-specific retirement studies, which began in early 2021. The pipeline and transmission system impacts of the transition will be an important part of these studies.

The scores of all fourteen resource plans across the evaluation metrics are presented in Part VI. As shown in the table, RP8 had the highest score under all but one of the metrics. Combined with DESC's informed judgement as an operating utility and its specific understanding of the operating and reliability conditions on its generating system, the needs of its customers and the nature of its service territory, it is DESC's conclusion that RP8 is the most reasonable and prudent resource plan to pursue at this time.

At the Commission's instruction, DESC has modeled six modifications of RP7 that were specified by the South Carolina Solar Business Alliance ("SCSBA") and Order No. 2020-832. These modifications involve accelerating the initial addition of solar resources to the system by three years (from 2026 to 2023) to take advantage of federal Investment Tax Credits ("ITCs") that were anticipated to otherwise decline from 22% to 10%. These plans modeled those solar additions at three price points provided by the SCSBA to the Commission and in configurations with and without battery storage. The modeling shows that under the most likely sets of sensitivities, and even at the lowest price point suggested by the SCSBA, accelerating the acquisition of these resources will increase costs to customers compared to waiting until 2026 as Resource Plan 7 ("RP7") assumes. And on a levelized basis, RP8 remains the low cost plan. For that reason, the modeling shows that neither the RP7a nor RP7b plans are preferable to RP7 or RP8. This is due in part to the fact that delaying the addition of solar and battery storage reduces costs to customers since the costs of these assets are declining. In addition, the Consolidated Appropriations Act 2021, H.R. 133, adopted on December 28, 2020, extended the operative ITC deadlines by two full years so that with proper planning, a 22% or even a 26% ITC can be obtained for assets that enter service in 2026.

This Modified 2020 IRP does not identify any new generating capacity that is required to be added to the system in the near term. DESC will continue to explore opportunities to improve reliability or otherwise benefit customers. That said, no near-term resource procurements are identified under RP8 before 2026 or anticipated as a result of the findings of this Modified 2020 IRP.

In addition to the comprehensive analysis surrounding alternative plans, in compliance with Order No. 2020-832, the Modified 2020 IRP also provides an overview of DESC's 2019 generation and transmission operating results, storms and storm response, and transmission and distribution planning and upgrades.

Finally, DESC will work with stakeholders to determine if the PLEXOS modeling software is appropriate to meet the requirements of the IRP process. For background, as of February 2021, DESC's implementation of PLEXOS (which has been under way since early 2020) was in the final stages of calibration and quality control testing. As the Commission has required, DESC will engage with stakeholders regarding the input values and parameters to use in modeling scenarios under this software and the suitability of using alternatives to PLEXOS going forward. This consultation will begin in the first half of 2021. However, based on rigorous evaluation and experience, DESC strongly believes that PLEXOS will fully meet the model requirements referenced in Order No. 2020-832.

PLEXOS software is being successfully used today in stakeholder-centric planning processes conducted by entities like the PJM Interconnection, MISO, and NY-ISO; by public-facing bodies like the National Renewable Energy Laboratory (NREL), the United States Department of Energy, and the California Public Utilities Commission; and by over 350 customers worldwide including many consulting firms and other independent experts such as those that represent parties in these IRP proceedings.

DESC puts forth this Modified 2020 IRP with an eye to the future, looking forward to further evolution of the key factors and evaluation metrics as identified by Act No. 62 and the most recent IRP Order. In doing this, DESC recognizes the importance of meaningful stakeholder engagement and has taken specific steps to work towards an effective structured process to enhance the IRP process that will lead to reliable and cost-effective plans that align with the best interest of customers.

Our Company

Overview: DESC's Modified IRP Is Organized into Nine Parts

Part I of the Modified 2020 IRP provides an overview of DESC's system and service and an operating report on DESC's generation system.

Dominion Energy lineman preparing material for service.

Overview: DESC's Modified IRP Is Organized into Nine Parts

Part I of the Modified 2020 IRP provides an overview of DESC's system and service and an operating report on DESC's generation system. This section shows how in recent years DESC has reduced its dependence on coal generation, increased its percentage of solar generation, and provided a cleaner energy supply to its customers as a result. Part I further provides an in-depth discussion of the components of DESC's present generation mix, their operating results, and the current and future environmental regulations that apply to them. It explains Dominion Energy, Inc.'s ("Dominion Energy's") corporate-wide goal of net zero CO_2 and methane emissions by the year 2050 and support for environmental justice. As directed in Order No. 2020-832, this section and **Appendix E** include information concerning the Wateree Unit No. 2 generator stator damage and DESC's repair plan.

Part II provides an operating summary for DESC's transmission and distribution system. It presents DESC's modernization programs for these systems, and describes the on-going planning done to ensure the continued reliable and economical delivery of power to customers. Part II also provides a summary of the transmission projects currently planned by DESC. This transmission expansion plan is continuously reviewed and may change due to any number of factors. This summary of projects does not represent a commitment to build.

Part III presents the demand and energy forecast for DESC's electrical system over the next fifteen years. It analyzes the potential for high or low demand and energy growth rates based on potential economic growth rates in the service territory. This section specifically evaluates forecasted load from wholesale customers and the forecasted impacts of electric vehicles ("EVs") on DESC's system.

Part IV presents DESC's DSM and EE programs and their effect in reducing energy usage. It reports on the Rapid Assessment that the Company commissioned in response to Order No. 2020-832 to determine the cost-effectiveness and achievability of ramping up its current DSM portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024. A copy of the Rapid Assessment is attached as **Appendix D**. Finally, Part IV provides an action plan for the Company to complete a comprehensive DSM evaluation of the cost-effectiveness and achievability of DSM portfolios reaching 1% and higher savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%, for filing in the 2023 IRP.

Part V provides information concerning the amount of renewable generation forecasted under the fourteen resource plans. It discusses the operating challenges presented by intermittent and non-dispatchable solar resources and the role of energy storage and cogeneration/combined heat and power projects.

Part VI discusses the Company's analysis of the fourteen resource plans under 378 individual scenarios. It provides charts showing the relative cost of these plans on a levelized basis, their rate impact on customers, their effectiveness in reducing CO_2 emissions, the resulting fuel costs under them, and the amount of renewable resources they would add to the system.

Part VII presents the Company's Short-Term Action Plan, setting forth the Company's plans and goals for the next three years to implement its IRP.

Part VIII describes how the IRP and the modeling underlying it are utilized by other departments and business units at DESC for business and reliability planning. This is provided in response to a directive by the Commission in Order 2010-382.

Part IX presents the summary conclusions of the IRP.

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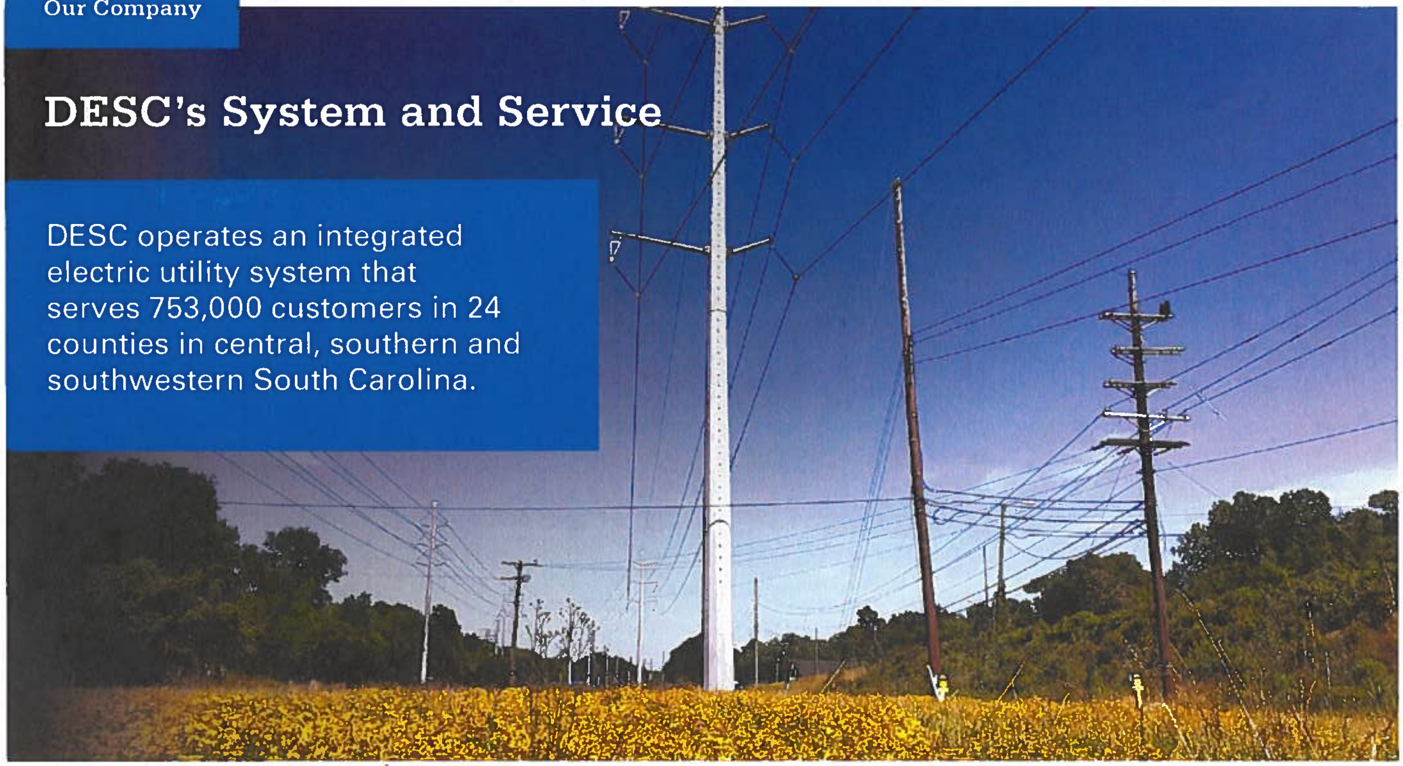
Our Company

DESC's System and Service

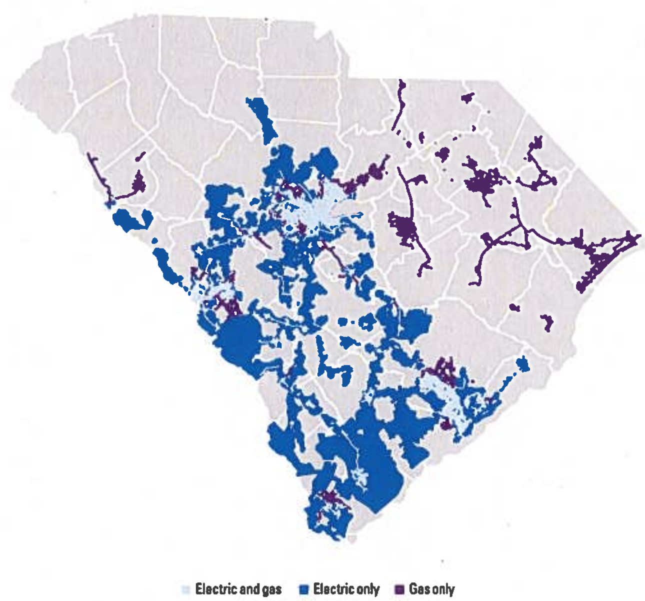
DESC operates an integrated electric utility system that serves 753,000 customers in 24 counties in central, southern and southwestern South Carolina.



Customers and Service Territory

DESC operates an integrated electric utility system that serves 753,000 customers in 24 counties in central, southern and southwestern South Carolina. DESC's service territory covers approximately 16,000 square miles and includes the metropolitan areas of Charleston, Columbia, Beaufort, and Aiken and many other smaller cities and towns, and rural areas in South Carolina.

South Carolina Service Area



Dominion Energy

DESC's System and Service

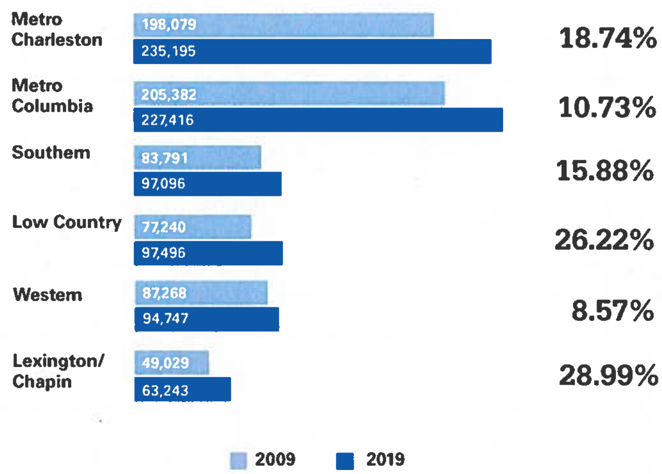
DESC's 2019 customer base includes 636,386 residential customers, 97,544 commercial customers, 784 industrial customers, 1,012 public street lighting customers and 3,659 other public authority customers. The municipal electric cities of Winnsboro and Orangeburg are wholesale customers that receive service under contracts regulated by the Federal Energy Regulatory Commission ("FERC"). These customer classes represented the following contribution to energy consumption and peak demand on the system in 2019.

Sales and Peak Demands by Customer Class

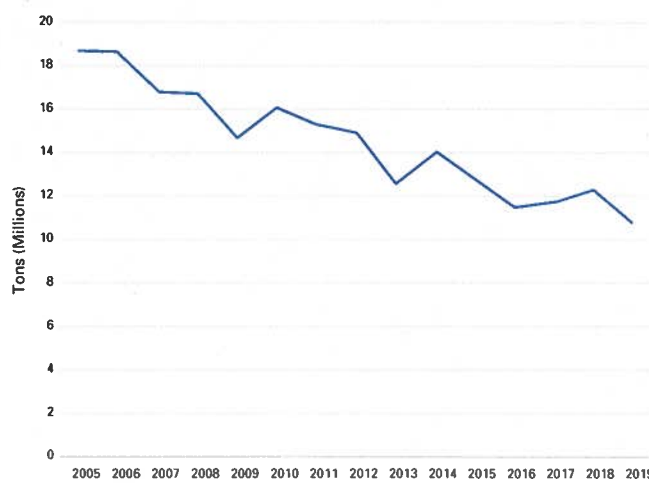
Class	Sales (GWh)	Peak Demand (KW)
Residential	8,335,977,498	2,023,062
Commercial	7,424,591,408	1,534,246
Industrial	5,693,722,427	869,193
Public Street Lighting	76,618,772	992
Other Public Authorities	524,476,608	89,112
Municipalities	882,367,244	178,123

South Carolina has a supportive business environment. It is an attractive place for industrial development, has reasonable housing costs, and has a growing population. Since 2009, DESC has added 86,203 net additional electric customers, an increase of 13.2%, with growth in the residential class representing 75,985 of these new customers. Growth in customer count has been concentrated in coastal areas and the Columbia area.

South Carolina Customer Growth by District/Region over a 10-year period[1]



Electric Carbon Emissions from 2005 to 2019[2]



DESC's Changing Generation Mix

The Decline of Coal

Over the past twenty years, the Company has pursued an aggressive program of coal station retirements and environmental upgrades at stations remaining in operation. As shown in the figure below, this has dramatically reduced DESC's CO_2 emissions and its exposure to potential future CO_2 emissions costs and regulations. In 2019, coal supplied only 23% of the energy generated by DESC, down from 69% in 2005. In 2019, 48% of DESC's power was generated by natural gas, up from 12% in 2005.

[1] There is some overlap among the regions.
[2] This CO_2 emissions chart is based on data collected by DESC using methodologies and conventions that were in place at the time DESC was acquired by Dominion Energy, Inc. In support of Dominion Energy's company-wide net zero carbon commitment, and as part of the integration of the DESC's data collection processes into those of Dominion Energy and its subsidiaries, these methodologies and conventions are in the process of being reviewed. Future reporting on carbon and other emissions may be based on different methodologies and conventions, and changes in the data presented may result.

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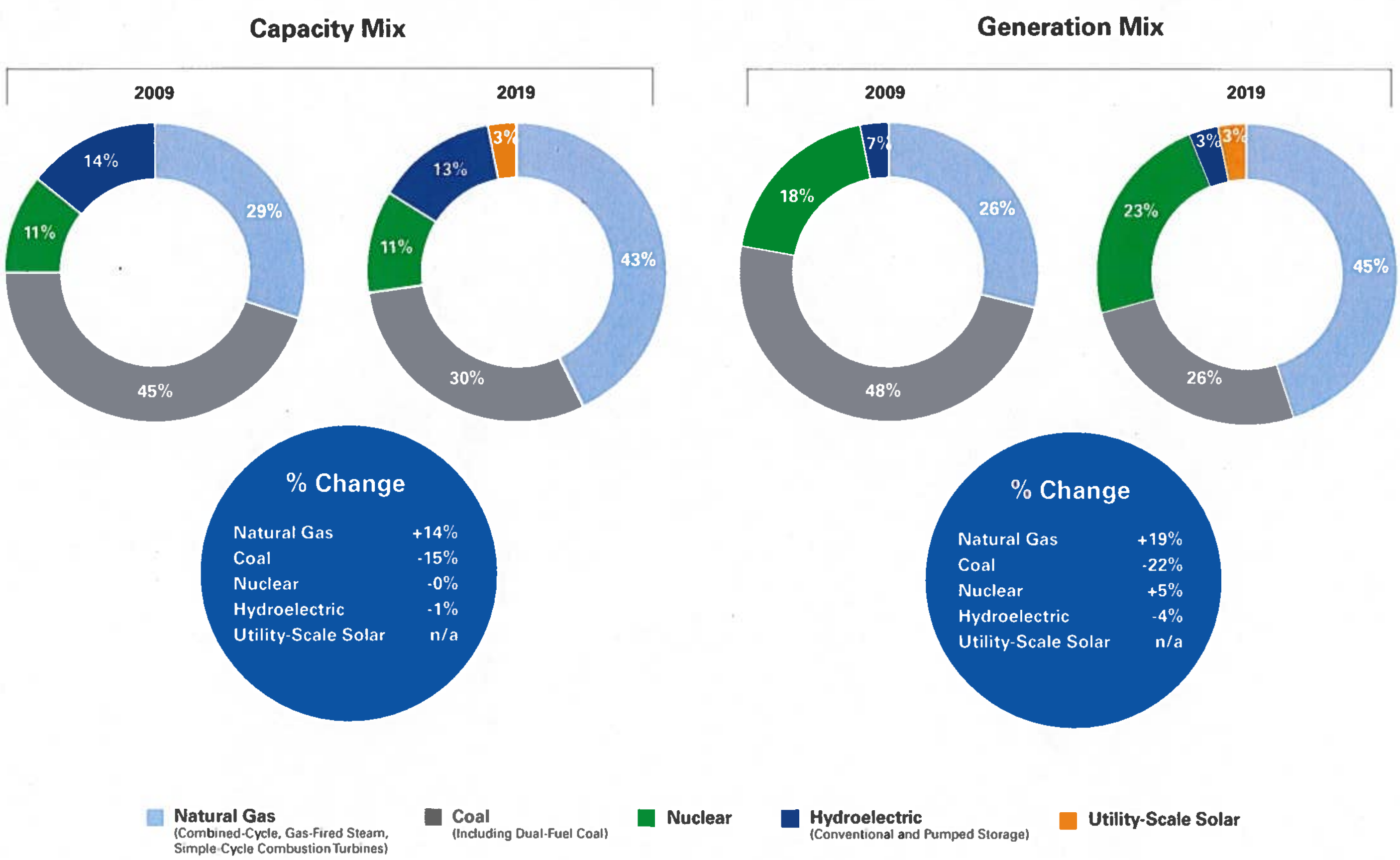
DESC's System and Service

Behind this transformation in fuel mix is the retirement or repowering of eight coal units. In 2012-2013, the 385 MW three-unit coal-fired Canadys Station was retired. A 95 MW conventional steam unit at Urquhart Station and the two-unit 250 MW McMeekin Station conventional steam units were converted from coal burning units to gas-fired only units in 2013 and 2014, respectively. In 2002, Units 1 and 2 at Urquhart were repowered from 75 MW coal-fired units to a gas-fired combined cycle arrangement (440 MW), adding almost 300 MW of new net capacity to the system. In June 2016, dual-fuel (coal and natural gas) firing capability was restored at the single-unit 415 MW Cope Station, which now frequently runs entirely on natural gas when adequate supplies of low-cost natural gas are available. In 2018, DESC sold its interest in the 85 MW coal/biomass-fueled generator at the Kapstone facility in North Charleston. In 2018, DESC replaced retired coal generation by purchasing the 519-megawatt combined-cycle Columbia Energy Center. This table shows DESC's current power generation supply mix.

Dominion Energy South Carolina Power Generation Supply Mix



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DESC's System and Service

The Growth of Solar

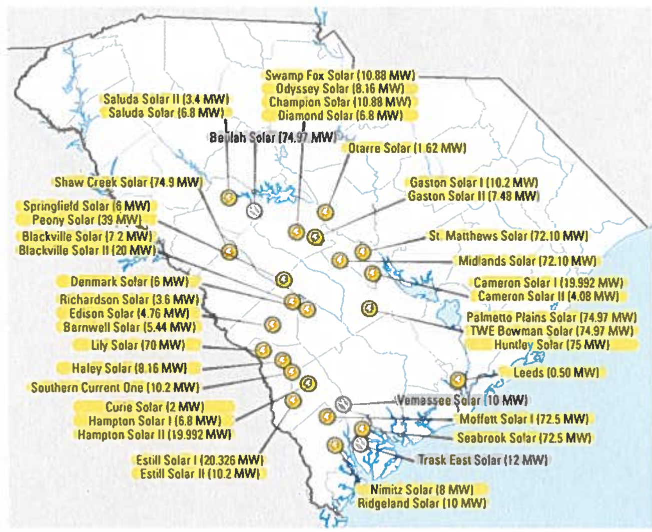
During the past five years, solar capacity on DESC's system has grown dramatically from a negligible amount in 2004 to 888 MW of utility scale solar and 114 MW of customer scale solar in 2019. By December of 2021, utility scale solar will have increased to 973 MW.The Southern Alliance for Clean Energy's *Solar in the Southeast Report* found that DESC had the second most solar watts per customer among the major southeast utilities and found that South Carolina is outpacing all other Southeastern states in increasing solar watts per customer.

As a result, in 2019, solar energy represented 3% of DESC's energy production. Including existing and scheduled utility scale solar, over 20% of DESC's retail summer peak hour generation in 2021 is expected to come from solar facilities. In 2019, solar purchases during the calendar year supplied 866,265 MWh of the energy used on DESC's system.

Declining Air Emissions for a Cleaner Generation Fleet

The retirement of coal units, the increased reliance on lower emitting natural gas, additional solar generation and investment in pollution control technology have allowed DESC to reduce both its CO_2 and non-CO_2 air emissions dramatically over the past 15 years. All units are controlled using a combination of control equipment appropriate for the station including air pollution controls such as scrubbers for sulfur dioxide, nitrogen oxide controls, particulate controls and mercury controls.This strategy has resulted in significant reductions of air pollutants such as nitrous oxide ("NOx"), sulfur dioxide ("SO_2"), PM, and mercury ("Hg") and has also reduced the amount of coal ash generated and the amount of water withdrawn. Since 2005, SO_2 emissions have fallen by over 98% and nitrous oxide NOx emissions have fallen by 84%. Since 2012, mercury emissions have fallen by over 84% (Hg emissions were not monitored prior to that time).

Map of Utility-Scale PV Solar Facilities in the DESC Electric Service Territory



DESC Power Generation Air Emissions as Reported by Continuous Emissions Monitoring Systems ("CEMS")

Year	SO_2 (tons)	NO_X (tons)	Hg (lbs)
2005	108,085	26,909	n/a
2006	106,582	26,537	n/a
2007	96,719	23,269	n/a
2008	97,056	23,040	n/a
2009	67,154	9,239	n/a
2010	48,482	10,177	n/a
2011	33,639	10,196	n/a
2012	27,890	9,162	144
2013	19,305	7,012	109
2014	16,768	7,608	69
2015	5,057	5,755	21
2016	2,659	5,414	12
2017	2,710	5,586	15
2018	2,529	5,779	20
2019	1,360	4,395	22
% Change	-99%	-84%	-85%

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Declining Fuel Costs

In addition, increased reliance on natural gas coupled with low natural gas prices and reliable nuclear generation have benefited customers in the form of reduced fuel costs. Since 2009, base fuel costs paid by DESC's customers have declined by over $200 million.

2050 Net Zero Commitment

Dominion Energy and its operating companies have recently entered a new phase in their long-term efforts to reduce air emissions from their utility operations. On February 11, 2020, Dominion Energy announced a new company-wide commitment to achieve net zero carbon dioxide and methane emissions by 2050 across all of its electric and natural gas operations in all states where it does business. This commitment recognizes and affirms the increased expectations and interest among customers, policy-makers, and employees in building a clean energy future.

Net zero does not mean eliminating all emissions. It instead means aggressively reducing emissions and ensuring that any emissions that cannot be eliminated economically or practically are offset by programs to remove an equivalent amount of CO_2 or methane from the atmosphere. Off-setting programs can include verifiable measures like carbon capture, reforestation, or negative-emissions technologies such as renewable natural gas.

Dominion Energy's recent commitment to net zero CO_2 and methane emissions builds on a strong history of environmental stewardship. Dominion Energy operating companies have already begun to transition the generation fleet, as well as transmission and distribution systems, to achieve a cleaner future. Collectively, DESC and other Dominion Energy, Inc. companies have:

- Retired over 3,000 MW of coal-fired and inflexible, higher cost fuel oil- and natural gas-fired generation over the past ten years;
- Since 2013, invested more than $5 billion in renewables and have increased their total solar generation portfolio (in operation or development) from 41 megawatts to over 5,700 MW, enough power to supply 1.4 million homes at peak output;
- Continued to operate 6,584 MW of non-carbon emitting nuclear units;
- Completed construction of the Coastal Virginia Offshore Wind demonstration project and secured Federal lease rights and are continuing to develop an approximately 2,600 MW offshore wind farm off the coast of Virginia. When fully constructed in 2026, the Dominion Energy Coastal Virginia Offshore Wind farm will deliver more than 8 million MWh of clean, renewable energy to the grid annually, avoiding as much as 4.877 million tons of carbon dioxide emissions annually — the equivalent of taking more than 1 million non-EV cars off the road for one year or planting more than 80 million trees; and
- Continued to modernize and transform the Companies distribution systems and installing Advanced Metering Infrastructure ("AMI") to provide an enhanced platform for DSM programs that provide more ways for customers to save energy and money through demand reduction measures and other rate offerings.

Fuel Cost Factor (cents per kWh)

May 2009-April 2020	3.621
May 2010-April 2011	3.61
May 2011-April 2012	3.586
May 2012-April 2013	3.541
May 2013-April 2014	3.278
May 2014-April 2015	3.325
May 2015-April 2016	3.137
May 2016-April 2017	2.445
May 2017-April 2018	2.451
May 2018-April 2019	2.451
May 2019-April 2020	2.451

DESC's System and Service

Dominion Energy has been actively lowering its CO_2 and methane emissions by employing existing technology and resources, such as extending the licenses of its zero-carbon nuclear fleet; rapidly expanding wind and solar resources; continuing to rely on lower emitting natural gas; promoting the use of electric vehicles and energy efficiency; and investing in renewable natural gas.

Nuclear energy is an essential component in achieving net zero. V.C. Summer Nuclear Station will be able to support these goals well into the future as DESC will operate under the current license extension from 2022 to 2042. Then DESC expects to request and receive approval of a subsequent license renewal, extending its licensed operation to 2062. Dominion Energy continuously monitors internal operations and external factors (e.g., technology, public policy, stakeholder feedback) to assess for appropriateness in all of its sustainability commitments, including its climate goals.

Achieving net zero CO_2 and methane emissions will require technological advancements in the utility sector and broader investments in technology across the entire economy in the long term. Through a dedicated innovation group, Dominion Energy is investing in the development of new approaches to the capture and sequestration of carbon produced by natural gas combustion turbines, the use of electric vehicles as battery resources for the grid, the use and generation of clean hydrogen and renewable natural gas, improving the output of solar generation, new sources of medium and long-term energy storage for the grid, and new approaches for generating carbon offsets including forestry and direct air carbon capture. Additionally, Dominion Energy is a partner in the Gas Technology Institute and Electric Power Research Institute's Low Carbon Resource Initiative, which is advancing the next generation of clean technologies critical to achieving net zero emissions through hydrogen and low carbon fuel production, transportation, and end use.

In the near term, Dominion Energy will continue to explore new technologies to accelerate progress in achieving its methane reduction goal. Dominion Energy currently deploys an industry-leading methane emissions reduction program that is one of the most aggressive and sweeping in the nation. Dominion Energy has committed to achieving a 65% reduction in methane emissions by 2030 and an 80% reduction by 2040[3].

In addition, Dominion Energy has partnered with the nation's largest hog and dairy producers to turn farm waste into clean renewable natural gas. By 2029, these projects will reduce methane emissions from the nation's farms by

Dominion Energy offshore wind.

the same amount as taking 750,000 cars off the road or planting 50 million new trees each year.

Overall, Dominion Energy is committed to pursuing all reasonable paths to assure its goal of net zero CO_2 and methane emissions is achieved while maintaining the reliable utility service. As it works toward the 2050 goal, Dominion Energy will be open and transparent about the progress being made through public disclosures, including Integrated Resource Plans and annual Sustainability and Corporate Responsibility reports.

Over the long term, achieving the clean energy goals of South Carolina and the Company will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy. This includes support for the testing and deployment of technologies such as large-scale energy storage, hydrogen, advanced nuclear, and carbon capture and sequestration, all of which have the potential to significantly reduce carbon emissions.

[3]As compared to 2010 methane emissions.

Dominion Energy

Our Company

Environmental Justice

Dominion Energy companies are committed to engaging with local communities, stakeholders and customers on environmental issues important to them, including environmental justice considerations such as fair treatment, inclusive involvement and effective communication. Fulfilling this commitment involves increasing the scope and inclusiveness of our stakeholder engagement on decisions regarding the siting and operation of energy infrastructure. DESC intend to partner with local communities on these issues and include all people and communities regardless of race, color, national origin, or income to ensure a diversity of views in our public engagement process.

DESC's Current Generation

DESC's currently operates 66 hydro and fossil generating facilities with a dependable net summer generating capacity of 5,009 MW and a single unit nuclear station with a net dependable summer generating capacity of 650 MW.These resources are supplemented by 973 MW of solar generation purchased from third parties under long-term power purchase agreements ("PPA") and an additional 114 MW of customer scale solar. DESC also benefits from a 20 MW allocation of power from the Southeastern Power Administration, which operates hydro resources on the upper Savannah River.

Location	In-Service Date	Probable Retirement[1] Date	Summer 2020 (MW)	Winter 2020 (MW)
Coal-Fired Steam				
Wateree - Eastover, SC	1970	2044	684	684
Williams - Goose Creek, SC[2]	1973	2047	605	610
Cope[4] - Cope, SC	1996	2071	415	415
Total Coal-Fired Steam Capacity			**1.704**	**1,709**
Gas-Fired Steam				
McMeekin - Irmo, SC	1958	2028	250	250
Urquhart - Beech Island, SC	1954	2028	95	96
Total Gas-Fired Steam Capacity			**345**	**346**
Nuclear				
V.C. Summer - Jenkinsville, SC	1982	2062	**650**	**662**
Gas Turbines				
Hardeeville, SC	1968	2018	0	0
Urquhart 1, 2, 3 - Beech Island, SC	1969	2044	39	48
Urquhart 4 - Beech Island SC	1999	2059	48	49
Coit - Columbia, SC	1969	2029	26	36
Parr - Parr, SC	1970	2030	60	73
Bushy Park - Goose Creek, SC	1997	2057	40	52
Hagood 4 - Charleston, SC	1991	2051	88	99
Hagood 5 - Charleston, SC	2010	2070	18	21
Hagood 6 - Charleston, SC	2010	2070	20	21
Urquhart Comb. Cycle - Beech Isl., SC	2002	2077	458	484
Jasper Comb. Cycle - Jasper, SC	2004	2079	852	924
CEC Comb. Cycle - Columbia, SC	2004	2079	519	586
Total I.C. Turbines Capacity			**2,168**	**2,393**
Hydro				
Neal Shoals - Carlisle, SC	1905	2055	3	4
Parr Shoals - Parr, SC	1914	2064	7	12
Stevens Creek - Near Martinez, GA	1929	2079	8	10
Saluda - Irmo, SC	1932	2082	198	198
Fairfield Pumped Storage - Parr, SC	1978	2128	576	576
Total Hydro Capacity			**792**	**800**
Other				
Southeastern Power Admin. (SEPA)			**20**	**20**
Total Firm Capacity			**5,679**	**5,930**
Solar[3]				
Company Owned	2011	2031	2.4	0
PPA DER Program	2015-2019	2039	64	0
PPA Non-DER Program	2017-2020	2040	762	0

1. Probable retirement dates are based on the 2014 Depreciation Study.
2. Williams Station is owned by South Carolina Generation Company ("GENCO"), a wholly-owned subsidiary of SCANA Corporation which is a wholly-owned subsidiary of Dominion Energy, Inc. and GENCO's electricity is sold exclusively to DESC.
3. Solar MW are nameplate values and do not represent the contribution to peak demand.
4. Cope Station is dual fuel and is run on both coal and natural gas.

Dominion Energy

DESC's System and Service

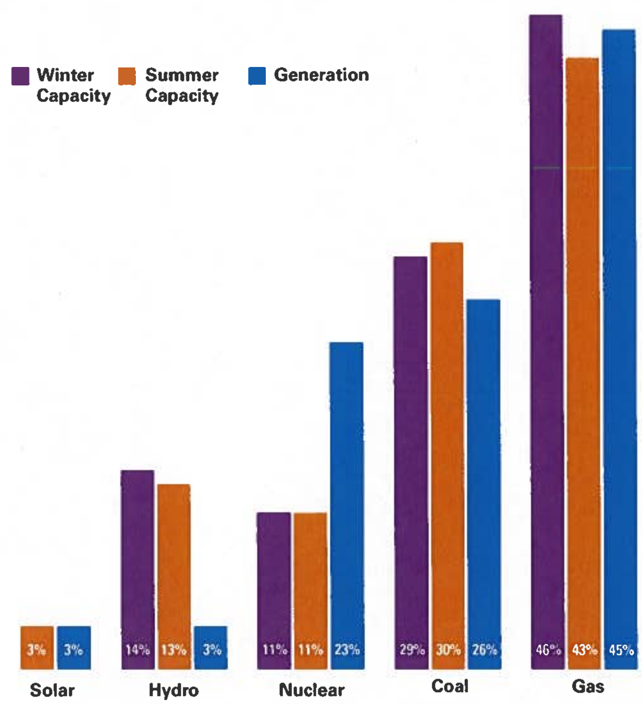
In 2019, the five major classes of generation contributed to DESC's safe, reliable and efficient electric service to customers in the percentages shown in the table to the right.

The data shows that in 2019, V.C. Summer Nuclear Station's energy production was disproportionately large compared to its contribution to meeting system capacity. This is not unusual. Due to its very low fuel costs and the benefits of sustained operation, Summer Station typically generates power at capacity in all hours of the year except during outages. With no refueling outage in 2019, and strong availability throughout the year, Summer Station served a much larger proportion of customers' energy needs than its contribution to meeting peak capacity needs would indicate.

In 2019, DESC's hydro units provided significantly less energy than their capacity contribution would indicate. Hydro units provide near-instantaneous responsiveness to dispatch orders, which makes them extraordinarily valuable for balancing and regulating the system in real time and responding to forced outages or other grid emergencies. To maximize their system value, hydro resources are often held in reserve so that they can be called on to add power to the system quickly when destabilizing events occur. In addition, the energy that can be created from hydro units is limited by river flows and reservoir capacities, so their utilization must be carefully timed where possible to ensure maximum value to the system. Because the Fairfield Pump Storage Unit stores energy generated by other units, its energy contribution is not reflected in the system energy totals to avoid double counting.

In 2019, coal units provided energy at a rate slightly less than their contribution to meeting capacity needs would indicate. This was due to shifts in coal prices relative to natural gas prices. Historically, coal has been a lower cost electric generation fuel than natural gas. However, the recent expansion of natural gas supplies and the dramatic reduction in natural gas prices has inverted this relationship. Often during 2019, natural gas was a cheaper fuel than coal for electric generation, and coal units were held in economic reserve to achieve fuel cost efficiency for customers. For that reason, in 2019 coal units contributed less energy to the grid than their contribution to meeting system capacity needs would indicate. For the same reasons, in 2019 gas generation made the largest contribution to meeting the system's needs, supplying slightly less than half of the system's capacity and energy.

Dominion Energy 2019 Resource Relative Contribution



In 2019, on a nameplate basis, solar was the fastest growing generation resource on DESC's system. But solar provided negligible capacity value because the solar generation profile and DESC's load profile are not congruent. Winter peaks largely occur in hours of darkness and summer peaks continue late into the evening after solar generation has begun to decline. For that reason, solar resources provide a much smaller contribution of the capacity used to meet customer demands than their energy production would indicate. The Company continues to assess combining solar technology with batteries and other storage technologies to optimize the amount of solar generation that can efficiently serve the Company's peak load demand.

Fossil-Steam Units' Operating Report

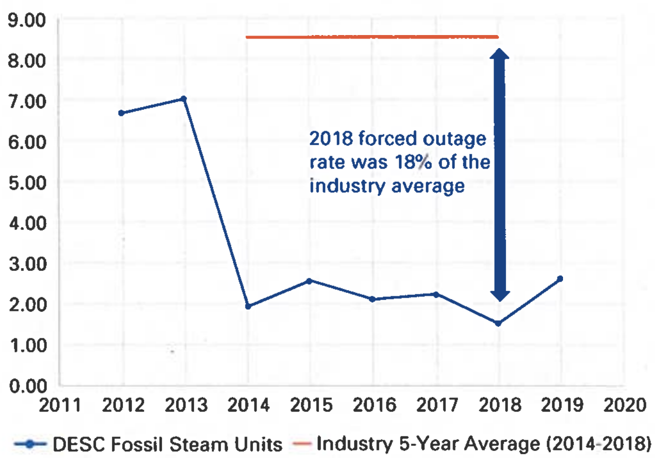
DESC's four existing coal units are the two-unit 684 MW Wateree Station, the one-unit 605 MW Williams Station and the one-unit 415 MW Cope Station. The Cope unit is dual fuel capable (coal and/or natural gas). It operates on interruptible natural gas when natural gas is available at prices that provide energy at a lower fuel cost than coal. Cope Station does not have firm gas transmission assigned to the plant.

These four coal units are well maintained and reliable. For reporting purposes, they are classified with three smaller gas-fired fossil-steam units located at McMeekin Station (250 MW) and Urquhart Station (95 MW). These units are 1950's era conventional steam units and that were originally designed and operated as coal-fired plants that have been reconfigured to burn gas only. In 2019, the forced outage rate for DESC's seven fossil-steam units was 2.62%. The five-year industry average for fossil steam units as reported for the period 2014 to 2018 was three times higher. As the chart shows, these units have been highly reliable over time.

During 2019, scheduled maintenance outages were conducted at Wateree, Williams and McMeekin Stations.

DESC's unit reliability data as reported to NERC is attached as Appendix O.

DESC Forced Outage Rate - All Fossil Steam Units (2012 - 2019)



Wateree Unit 2 Generator Stator Repairs

In February 2020, while Wateree Unit 2 was off line in economic reserve, a failed isolation valve allowed hydrogen gas to bleed by and collect in the generator housing. The isolation valve was locked out and tagged out at the time. The leaking hydrogen entered the generator housing through a line that was connected to the unit to feed instrument air into the generator housing to protect the generator stator windings while offline. The leaked hydrogen caused a small explosion internal to the generator. Damage was confined within the generator stator casing. The major components of the stator were undamaged. However, several rubber baffles that direct gas flow within the stator were dislocated. These baffles, although not particularly expensive themselves, cannot be replaced without entirely disassembling and rebuilding the stator.

DESC evaluated a range of repair options including disassembling and rebuilding the stator on-site, and replacing the stator with a used stator taken from similar-sized recently retired plants across the country. To minimize costs and execution risks, the decision was made to replace the existing stator with a new factory-built unit. It will be fabricated by Mitsubishi Power Americas, Inc. and installed by its subsidiary Mechanical Dynamics & Analysis (MD&A), a leading global supplier of large turbo-generators and provider of turbine-generator set maintenance, respectively. As presented in the testimony in Docket No. 2020-125-E, economic analysis showed that the short-term value of the unit's capacity and energy to the system fully justified the repair costs even if the unit were to be retired early.

The root cause of the incident was thoroughly investigated, and the hydrogen piping system has been redesigned and replaced to create a means to isolate the stator from the hydrogen source even if a valve leak occurs while instrument air is being applied to the unit. DESC implemented these changes to Wateree Unit 2's sister Unit 1 on site, in addition to evaluating potential failure modes for hydrogen systems at all of its facilities that employ hydrogen-cooled generators.

The stator repair plan was well underway in February of 2021, and major components of the new stator were being forged. The contractor has committed to have the new stator install and tested in time for the unit to be back in service in

May of 2022. Information responsive to the Commission's specific requests for information about the repair schedule, financial capability of the contractor, insurance coverage and contingency plans as contained in Order 2020-832 at pages 40-41 can be found in **Appendix E**.

Environmental Compliance

The Company's utility operations and construction activities are subject to a number of environmental laws and regulations which are constantly changing. Revised rules and new laws are likely under the Biden Administration.

Coal-fired generation is a particular focus for environmental compliance. DESC's three coal-fired generating stations are fully compliant with currently applicable emissions standards. All DESC ash landfills have been upgraded to Class III landfill standards. Ash ponds at McMeekin and Wateree Stations have been certified as closed by SC DHEC, and the ash ponds at the former Canadys Station site are largely dewatered and over 50% of the residual material has been removed through ongoing recycling. Studies are underway to determine what actions will be required for Williams, Urquhart Stations to comply with new Environmental Protection Agency ("EPA") Clean Water Act ("CWA") 316(b) regulations related to cooling water usage. Williams and Wateree Station may also require action to comply with new 2020 EPA Effluent Limit Guidelines ("ELG"). Additional details are outlined below.

New Source Performance Standards for Greenhouse Gas Emissions from Electric Generating Units

In October 2015, the EPA issued final Standards of Performance for Greenhouse Gas Emissions from new, modified, and reconstructed electric utility generating units. These standards apply to the new combined cycle and ICT units envisioned in the resource plans evaluated here, and these units will meet those standards. In December 2018, the EPA proposed revisions to these standards which do not apply to the units envisioned in the resource plans.

Affordable Clean Energy Rule

On June 19, 2019, the EPA released the final version of the Affordable Clean Energy Rule ("ACE Rule"), which replaced and repealed the Clean Power Plan. The ACE Rule applies to DESC's four existing coal-fired units. The ACE Rule includes unit-specific performance standards based on the degree of emission reduction levels achievable through heat rate efficiency improvements. In January of 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the rule, and this action will become effective when the mandate is issued by the court. It is expected that EPA will promulgate a new rule regulating greenhouse gas emissions from fossil fuel fired electric generating units, but it is unknown at this time how that replacement rule would affect DESC or what its cost might be.

Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule ("CSAPR") seeks to reduce emissions of SO_2 and NOx from power stations in the eastern half of the U.S. DESC fully complies with this rule, which has no present or planned impact on any existing units. The existing and envisioned units are expected to be in full compliance, so the rule does not affect DESC's IRP or retirement planning.

Mercury Air and Toxics Standards

The Mercury & Air Toxics Standards ("MATS") rule regulates mercury and hazardous air pollutant ("HAP") emissions from coal- and oil-fired power plants. All existing electric generating units that are subject to the rule are in compliance. No additional capital expenses are anticipated in relation to this rule.

Clean Water Act Section 316(b)

EPA issued final regulations effective October 2014 under Section 316(b) of the CWA to reduce impacts to fish, shellfish and other aquatic life from cooling water intake structures at certain electric generating facilities. DESC has five facilities with cooling water intakes that may require modification under this regulation. They include the Williams, Wateree and Cope coal-fired Stations, Urquhart Station and V.C. Summer Station. The rule establishes a national standard to reduce impacts, but delegates authority to state regulators to make certain facility-specific decisions about how to comply with the rule. DESC anticipates that it will have to install control technologies at certain of these facilities to comply with the rule. DESC is conducting studies to support determinations by state regulators. At this time, DESC cannot predict what actions may be required to comply with these regulations or their cost.

In addition, in January 13, 2021, the EPA published a memo that included a framework to inform state permit writers' evaluations regarding whether additional measures may be necessary at hydroelectric generating facilities under 316(b). DESC has five hydroelectric plants that are subject to 316(b) regulations: Neal Shoals, Parr, Fairfield, Saluda and Stevens Creek. The EPA under the Biden Administration may revisit, revise or withdraw this memo without further notice or comment. At this time DESC cannot anticipate what additional actions will be required by permitting authorities to protect aquatic life at these locations.

Effluent Limitation Guidelines

In September 2015, the EPA released a final rule to revise the Effluent Limitations Guidelines for steam electric generating units. The final rule established updated standards for wastewater discharges. Affected facilities are required to convert from wet coal ash management systems to dry or closed cycle systems, and potentially make other changes to wastewater treatment facilities to meet the new discharge limits related to these systems. In October 2020, the EPA released a final ELG rule. It revises the 2015 rule and establishes new limitations on the discharge of Flue Gas Desulfurization ("FGD") wastewater and Bottom Ash Transport Water ("BATW") and extends dates for compliance.

Williams and Wateree Stations will have to make retrofits and modifications to their systems to comply with the new ELG requirements. Under the ELG rule, a generation station that certifies by 2025 that it is retiring or eliminating coal fuel use by December 31, 2028, is subject to less stringent requirements. Other parts of the rule create alternate compliance paths for certain categories of facilities. The retirement studies for Williams and Wateree Stations will largely determine what approach will be taken to ELG compliance.

In those resource plans where Williams and Wateree Stations are assumed to remain in service after December 31, 2028, the IRP assumes that they implement the necessary modifications. The estimated costs of complying with the ELG rule are included in the capital cost forecasts used in modeling those resources in this Modified 2020 IRP.

Coal Combustion Residual Rule

In April 2015, the EPA adopted comprehensive rules for Coal Combustion Residuals ("CCR") landfills and ash ponds at active electric generating facilities. The rule requires that all unlined CCR ponds be retrofitted or closed within prescribed timeframes along with monitoring, corrective action, and post-closure care activities as necessary.

DESC had previously accomplished or taken voluntarily steps to meet the CCR rule mandates. There are no ponds regulated by CCR at Urquhart Station. (Urquhart never

Cope Station; Cope, South Carolina.

sluiced ash and all previous storage facilities have been certified closed by DHEC. The remaining low volume waste ponds are in the permitting process to achieve certified clean closure.) The plant was converted to natural gas before the effective date of CCR, and no ash was directed to ponds at Urquhart station after the effective date. Permanent closure of the McMeekin ash ponds was completed in 2006, and the station's on-site landfill was closed in 2016. The Canadys Station was decommissioned before the effective date of the CCR rule. The Company has been removing ash from the former Canadys ash ponds for beneficial reuse (recycling) for a number of years. Closure of the ponds there is awaiting receipt of certain remaining permits from SC DHEC.

In 2011, DESC and SC DHEC voluntarily reached an agreement to remove the ash and close the pond at Wateree Station on an accelerated basis. DESC installed a first of its kind bottom ash handling process where ash transport water is recycled, developed new Class III lined landfill capacity, and converted fly ash handling systems to a dry process. The clean closure of the Wateree ash pond was completed in November 2019. Going forward, all non-recycled coal ash will be deposited in Class III landfills.

Williams Station operates a lined CCR pond which collects solids from the station's FGD scrubber operations. In compliance with the CCR rule, modifications of this pond are underway and when complete the modified FGD pond will be certified to meet all CCR requirements.

In October of 2020, EPA issued an advanced notice of proposed rule making which could make the CCR rule applicable at certain inactive ash ponds at inactive generating stations. DESC is currently planning for the future closure of the ash ponds at the Canadys Station in accordance with state-approved closure plans. Depending on when the rule is finalized, the closure of the ash ponds at the Canadys site could be subject to the requirements under the revised CCR rule. Until the rule is final, DESC cannot determine whether any additional actions related to Canadys Station will be required.

Retirement Studies for Coal and Other Fossil Steam Units

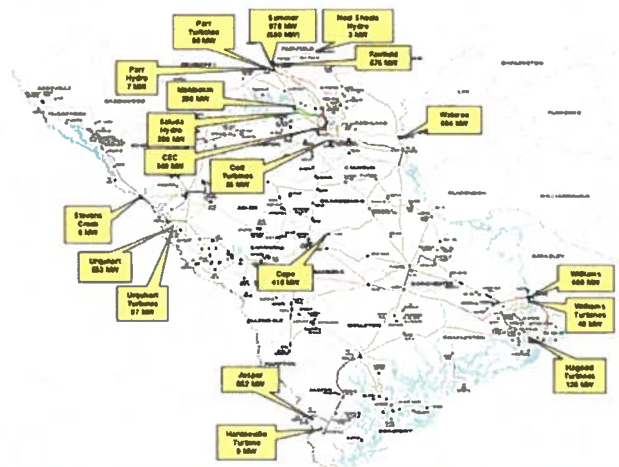
The retirement of generation resources requires a disciplined and carefully sequenced process to ensure system reliability. In 2021, the Company began studies to determine the potential benefits of retiring its four existing coal units before the end of their useful lives. Early retirement will also be evaluated for three older coal units that have been converted to gas-fired steam units (McMeekin Units 1 & 2, and Urquhart Unit 3). Retirement of these seven units would support Dominion Energy's commitment to a net-zero carbon future and would reduce customers' exposure to the future costs or restrictions imposed on carbon emissions.

The retirement of any major generation unit affects power flows and transmission constraints across the system. For that reason, unit retirements must be prioritized. The Power Flow, Stability, and Short Circuit Analysis for each retirement, among other transmission analyses, must take into account the effects of prior retirements. These parameters and analyses constitute the transmission impact analysis.

In this context, DESC has identified the retirement of the Wateree Units and the three gas fired steam units (McMeekin Units 1 & 2 and Urquhart Unit 3) as the retirements to be reviewed in the initial stage of the current retirement analysis. Williams Station and Cope Station will be studied in the following stages of the analysis.

Wateree Station is prioritized for initial consideration because at 684 MW it is the largest remaining coal station on DESC's system, and its retirement poses fewer

Locations of DESC's Generation Assets with Summer Ratings



challenges to the system than the alternatives. Wateree Station is located in the northern district of the DESC transmission system. For a number of reasons, including the historic availability of high-volume natural gas pipelines, rail service, land-use patterns and environmental restrictions, the majority of DESC's generation resources are located there. Approximately 3,100 MWs of generation are located in the Columbia area where Wateree Station is located. Natural gas supplies are generally accessible in this area. The availability of these generation resources and the relative accessibility of natural gas supply in the area will reduce the potential impact of retiring the Wateree Station on the reliability needs of the system. These facts support prioritizing evaluating the retirement of Wateree Station as a potentially cost-effective and feasible means of achieving significant CO_2 emissions reductions in the near term.

By contrast, the second largest coal-fired unit, Williams Station, is located outside of Charleston, which is DESC's largest and fastest growing load center. DESC has only 771 MWs of generation capacity available in the area, and Williams Station represents 78% of that capacity. Given land use patterns and land values, the area has not been attractive to solar developers. Even today, maintaining reliable service to the Charleston area is challenging when Williams Station is off line for maintenance or otherwise unavailable.

Dominion Energy

In addition, generation supply in the South Carolina Low Country is becoming increasingly constrained. Santee Cooper, whose Low Country transmission and generation system is extensively interconnected with DESC's, has announced plans to retire its four-unit Winyah coal-generation plant (1,150 MW), located near Georgetown, and is considering retirement of some or all of its four-unit Cross coal-generation plant (2,375 MW) in Berkeley County.

Future coal plant retirements may require additional generation to be sited in the Low Country. The Charleston area currently lacks the high-volume natural gas pipeline infrastructure needed to support a new large combined-cycle gas generation facility, and bringing natural gas supplies to the area may need to be a significant part of any plan to retire Williams Station. This affects both costs and time. For these reasons, in sequencing the retirement studies a potential Wateree Station retirement will be prioritized above retirement of Williams Station.

The three gas-fired steam units (McMeekin Units 1 & 2 and Urquhart Unit 3, collectively 345 MW) have been in service since the 1950s. They have relatively high heat rates (i.e., low fuel efficiency) and produce more carbon emissions per MWh than modern, gas-fired generation units. For that reason, retiring them would support DESC's commitment to the goal of net-zero carbon emissions by 2050, but not as much as retiring a comparable quantity of coal generation. In addition, the three gas-fired steam units are located in DESC's northern district where other generation sources are concentrated. Natural gas supplies are available on the McMeekin and Urquhart sites. This creates the potential to replace these units with modern natural gas-fired generation assets without materially impacting power flows and triggering extensive transmission upgrades. These facts support prioritizing the retirement of these units as a potential near-term means of reducing CO_2 emissions second to retiring Wateree Station.

Cope Station is the remaining resource to be considered for retirement. It is a modern coal unit that entered service in 1996. Cope can run entirely on natural gas but is not as fuel efficient when doing so as a modern combined-cycle natural gas unit. But as a dual fuel unit, Cope Station can be run on natural gas to reduce CO_2 emissions, while maintaining the ability to switch to coal if gas supply issues occur and supplies are interrupted. In addition, Cope Station will not require significant capital investment to comply with ELG rules, as Williams and Wateree will. For these reasons, the retirement of Cope Station will not be sequenced ahead of other potential unit retirements in the retirement analysis.

Retirement Candidate Rankings

Overall Rank	Unit Name	Winter Peak Capacity (MW)	Fuel/ Fuel Diversity	Projected Capacity Factor	In-Service Date
1	Wateree	684	Coal	27%	1970
2	Urquhart 3 Steam	96	Gas	9%	1954
3	McMeekin 1 and 2	250	Gas	37%	1958
4	Williams	610	Coal	53%	1973
5	Cope	415	Coal or Gas	51%	1996
	Total	2,055			

To conduct these retirement studies, DESC will use PLEXOS resource optimization software to determine the optimum timing of retirements under given assumptions and sensitivities and to identify the optimum suite of replacement resources. As of early February 2021, the PLEXOS resource optimization software has been configured to model DESC's generation portfolio and system and is undergoing final calibration and quality control testing. In finalizing the modeling plan, DESC will consult with the IRP Stakeholder Advisory Committee concerning the appropriate load growth, fuel costs, CO_2 costs, construction costs and other inputs. Optimization studies will use these inputs and sensitivities to identify the appropriate year of the retirement for each unit and the most cost-effective combination of replacement resources. Included in these resource plans evaluations will be engineering estimates of net salvage costs and environmental remediation costs for each of the sites. The resulting resource plans will then be provided to transmission planning to prepare interconnection studies to determine the reliability impacts and required transmission investment to support each of the resource plans. The end result will be an optimized date and resource plan for the retirement and replacement of each set of assets. Additional costs to customers from the retirements and indicative impacts on rates will also be provided.

Nuclear Operating Report

Since January 1984, DESC has operated the 971 MW single nuclear unit pressurized water reactor at V.C. Summer Nuclear Station safely and efficiently. DESC owns two-thirds of the Summer Station's capacity and the South Carolina Public Service Authority, Santee Cooper, owns the balance. In 2019, Summer Station produced over 5,720 gigawatt-hours ("GWh") of non-carbon emitting base-load energy, which represented 20% of DESC's total energy production in 2019. Energy produced by Summer Station during that year displaced approximately 3.2 million tons of CO_2 that would have been emitted if replaced by fossil resources.

The Summer nuclear unit is licensed to operate until August 2042. A subsequent license renewal is anticipated to extend operations to 2062. In 2019, the operations at Summer Station were integrated into the Dominion Energy, Inc. seven-unit nuclear fleet creating economies of scope and scale and deepening the pool of expertise and experience available to maximize operational efficiency, reduce operating costs, and shorten refueling outages.

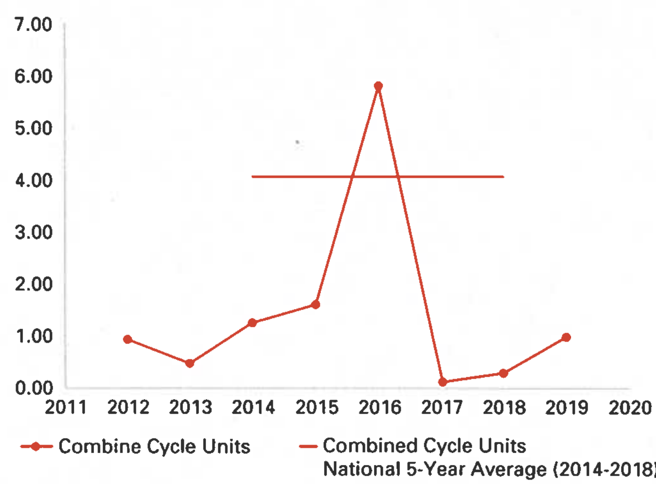
In 2019, Summer Station met or exceeded all Nuclear Regulatory Commission safety and environmental requirements and has received favorable ratings from the Institute of Nuclear Power Operations ("INPO") operational standards assessment. In 2019, Summer Station's net capacity factor, computed under the provisions of S.C. Code Ann. § 58-27-865, was 101.78%, indicating a high degree of reliability. The 2019 gross generation output was 8,581,185 megawatt hours. There was no refueling outage or other scheduled maintenance outage during 2019.

Combined Cycle Gas Plants Operating Report

DESC operates three combined cycle natural gas fired plants, the 852 MW Jasper Station, the 519 MW Columbia Energy Center, and the 485 MW Urquhart Combined Cycle Unit. Because of low natural gas prices and the fuel efficiency of these units, they are currently run intensively and provided 42.77% of DESC's 2019 electric generation (not including solar PPA contribution). During 2019, DESC's forced outage rate for combined cycle units was 0.76%, which was approximately 75% lower than the national

Jasper Station; Hardeeville, South Carolina.

DESC Combined Cycle Forced Outage Rate (2012-2019)



average of 4% for the years 2014-2018. The forced outage rate for DESC's combined cycle units has been at 1% or less for seven of the past eight years

Internal Combustion Turbines Operating Report

DESC operates sixteen simple cycle internal combustion turbines that provide peaking capacity, spinning reserves and local voltage support as needed. Many provide black-start capability in case part of the transmission system loses power and must be restarted and resynchronized to the grid. Certain of these units fill a nuclear safety role by providing emergency backup power for the V.C. Summer Nuclear Station. The remaining units are located at multiple sites across DESC's system. Collectively, the sixteen units represent 339 MW of capacity.

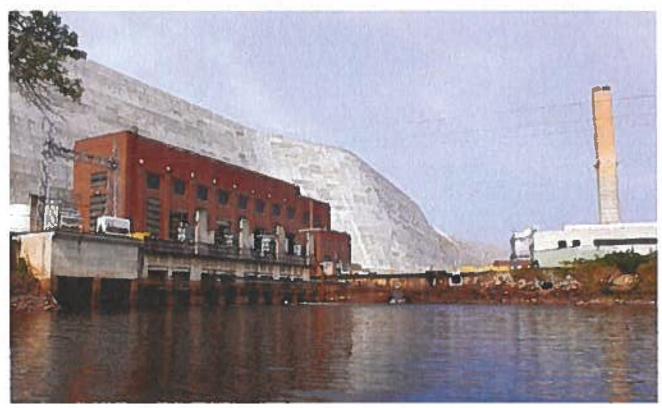
Because of their fast-start capabilities and operational flexibility, these units have been placed under increasing operating pressure to follow loads in response to variations and intermittency in solar generation. The median age of these units is 49 years. This age coupled with the shorter-lived nature of the technology that these units represent has resulted in maintenance and reliability issues. Because of the importance of these units to system reliability and their increasing importance in managing solar intermittency, DESC is actively pursuing a strategy for replacement of a number of the older units with new, high-efficiency fast-start combustion turbine units. The selection of the number, technology and location of the replacement units will be complete in early 2021. The decision to replace the units will be based on specific operating and reliability concerns rather than system-wide resource planning considerations such as those that are modeled in an IRP. Once decisions concerning the replacement of the units are made, the operating characteristics of the new units will be incorporated in DESC's resource planning models and reflected in future IRP updates, avoided cost calculations and fuel cost forecasts.

Hydro-Power Operating Report

DESC's five hydroelectric generating plants represent 792 MW of non-carbon emitting capacity whose unique operating abilities provide important reliability benefits for the system and its customers.

When demands on the system are low, the Fairfield Pumped Storage Unit pumps water from the Broad River/Parr Shoals Reservoir into an elevated reservoir at Lake Monticello. The unit releases that water to generate hydro power in times

Fairfield Pumped Storage Facility; Jenkinsville, South Carolina.



Saluda Hydro Plant; Columbia, South Carolina.

of higher demand or to meet emergencies on the system. Fairfield Pumped Storage has a net dependable generating capacity of 576 MW and is DESC's largest hydro station.

Fairfield Pumped Storage can respond almost instantaneously to events on the system to protect reliability, grid stability, and power quality. For that reason, it is uniquely valuable to DESC and its customers. With the growth in solar capacity on the system, Fairfield Pumped Storage is increasingly used to absorb variations in intermittent solar generation as weather conditions change and to store power generated during sunny periods for use when solar facilities are idle. The FERC license for the project was renewed for fifty years on November 25, 2020.

In 2019, Fairfield Pumped Storage returned to the system 469.5 GWh of stored energy and achieved a forced outage rate of 1.13%. Given the operating characteristics of pumped storage, there is a planned maintenance outage of two of the eight units every spring and fall.

DESC operates four traditional hydroelectric plants with a combined capacity of 216 MW and an average age of 99 years. In 2019, DESC's hydroelectric plants produced 288.1 GWh of energy for DESC customers. The Saluda Hydro plant (for which Lake Murray is the reservoir) is the largest traditional hydro unit on DESC's system at 198 MW. In August 2008, DESC filed an application with FERC for a renewed fifty-year license for Saluda Hydro. The Company anticipates the issuance of this new license in due course. In 2019, Saluda Hydro generated 142 GWhs of energy and achieved a forced outage rate of 8.04%.

In 2018, the Company filed to renew the Stevens Creek Hydroelectric Project, which expires in October 2025. Stevens Creek is located in Georgia and provides 8 MW of capacity to the system.

Southeast Energy Exchange Market

On February 12, 2021, a group of utilities filed a request for FERC to authorize a new Southeast Energy Exchange Market ("SEEM"). SEEM will provide an automated, intra-hour trading platform to let electric utilities in the Southeast buy and sell energy through a secure software system using unused transmission capacity. The trading platform will match bids and offers voluntarily submitted by participants for 15-minute intervals of energy supply within the upcoming hour. Unused available transmission resources will be utilized with no charge except for losses. Transactions will be priced at the midpoint between the offer price and bid price creating value for customers on both sides of the transaction.

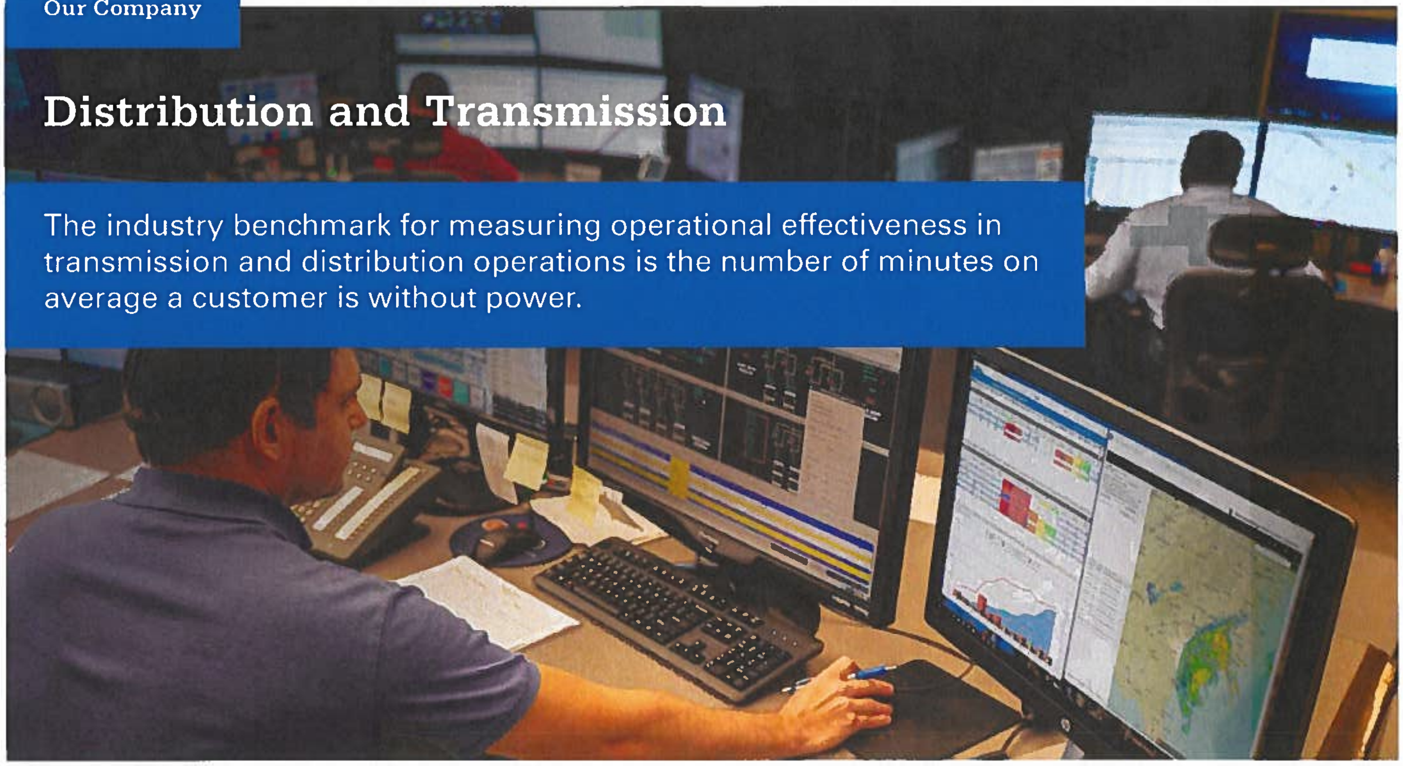
SEEM will act as an overlay to the existing bilateral market to increase efficiency. It will not replace any bilateral market or existing agreements or obligations. It aims to save customers money by allowing participating companies to more efficiently enter into bilateral agreements for short term energy sales where economies can be achieved.

SEEM will be a voluntary organization comprised of regional generation operators and Load Serving Entities that are independent of market structures like RTOs and ISOs. DESC will be a founding member, along with subsidiaries of Southern Company, Duke Power, AEP, LG&E, Kentucky Utilities, TVA and numerous public power and electric cooperative entities. The founding entities collectively own approximately 160,000 MW of generating capacity and serve about 640 TWh of energy for load across 10 Balancing Authority Areas and two time zones. SEEM will allow for better integration of diverse generation resources, including renewables, and will reduce renewable curtailments. A benefits analysis was performed and confirmed that the SEEM's benefits will scale with the addition of more solar and wind resources in the region. The anticipated start date for operations and power flow is in the first quarter of 2022.

Dominion Energy

Distribution and Transmission

The industry benchmark for measuring operational effectiveness in transmission and distribution operations is the number of minutes on average a customer is without power.



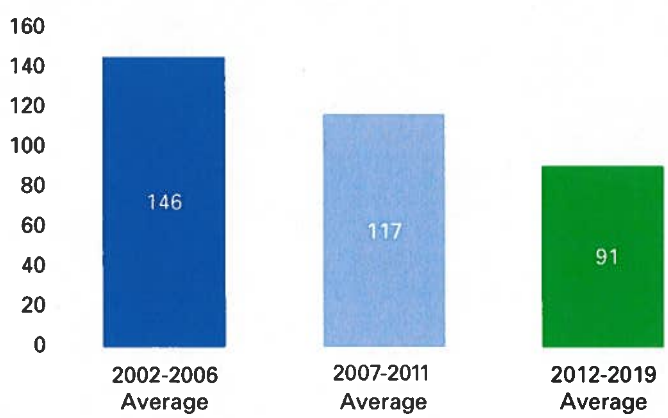
Dedicated employees at 24/7 System Control; Cayce, South Carolina.

Distribution and Transmission Operating Report

The industry benchmark for measuring operational effectiveness in transmission and distribution operations is the number of minutes on average a customer is without power. This is reported as SAIDI, the System Average Interruption Duration Index. A lower SAIDI score indicates more reliable transmission and distribution systems. DESC's 2019 SAIDI score was 77.8 minutes which is an historically low level. As reported by the State Energy Office, DESC provided its customers a level of reliability in 2019 that was forty-nine percent better than the other regional investor-owned utilities evaluated by that office.[4]

These SAIDI scores reflect years of disciplined and effective vegetation management, timely inspection and replacement of aging transmission and distribution infrastructure, resilient transmission assets, and investment in automated switching technology on the distribution system to minimize outage durations and reduce storm damage.

SAIDI Average Comparison Score



Modernization through Smart Switching and SCADA

DESC is continuing to expand Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices throughout the distribution and transmission system. DESC has approximately 1,100 distribution SCADA switches, which allow power flows to be rerouted remotely in response to outages. On distribution circuits, the newer and more sophisticated devices can detect system outages and operate automatically to isolate sections of

[4] http://energy.sc.gov/node/3065

Dominion Energy

line experiencing problems, thereby minimizing outage times and limiting the number of affected customers. Some of these isolating switches can communicate with each other to determine the optimal configuration to restore service to as many customers as possible without operator intervention. DESC continues to evaluate systems that will further enable these automated devices to communicate with each other and safely reconfigure the system in a fully automated fashion, identify and communicate to operators exactly where each faulted section of a line is located, and monitor the status of the system as it is affected by outages, switching, and customer generation (solar).

Storm Response

Hurricane Dorian was the only named storm to impact DESC's service territory in 2019. It brought sustained wind speeds of over 85 miles per hour to the Charleston area, 10 inches of rain to McClellanville, South Carolina and 17 hours of winds that exceeded tropical storm force in Charleston. In all, there were more than 279,000 Customers Affected (customers who lost service at one point or another in a storm), representing 80% of all Charleston customers. Service interruptions peaked on the afternoon of Thursday, September 5, 2019, and there were approximately 186,400 customers without power when the storm ended. Service was restored to all customers by Sunday evening, September 8, 2019, a little more than three days later.

In addition, the service territory experienced three other significant events that resulted in more than 10,000 customers losing power.

- On April 19, 2019, an unseasonably deep upper-level trough of low pressure and an associated surface low pressure combined with very strong low to mid-level winds to cause a strong squall line and damaging winds to develop that tracked eastward through the service territory ahead of a cold front. At peak, more than 53,000 customers were impacted. DESC worked quickly to restore customers resulting in customer average interruption duration ("CAIDI") for affected customers of minutes of 158.
- On June 20, 2019, a heavy wind and rain event occurred in DESC's service territory. This event registered powerful winds, including a 56 mph gust recorded at Columbia Metropolitan Airport and a 51 mph gust reported at Lake Murray. There were widespread reports of trees down throughout the Midlands causing traffic blockages on key downtown Columbia thoroughfares including Assembly Street, Gervais Street, Devine Street, and Rosewood Drive. At peak, more than 87,000 customers were impacted. DESC worked quickly to restore customers resulting in average CAIDI for affected customers of minutes of 192.
- Two days later, on June 22, 2019, severe thunderstorms moved through the entire service territory bringing tree limbs down and causing outages. At peak, more than 131,000 customers were impacted. DESC worked quickly to restore customers resulting in average CAIDI for affected customers of minutes of 156.

The availability of generation resources has not been an issue in responding to any recent storms. The Company is unaware of any case in which the availability of solar or other distributed generation has played a positive role in storm restoration efforts or reliability during storm events. Solar resources must be isolated from the grid during storm restoration for the safety of customers, the public and line crews. Solar assets are not suited for cold-load pick up at the conclusion of storm restoration efforts.

2019 Significant Weather Events

Event	Date	Customer Interrupted	CAIDI*
Strong squall line wind event	4/6/2019	53,203	158 minutes
Heavy wind & rain event	6/20/2019	87,196	192 minutes
Severe thunderstorm event	6/22/2019	131,136	156 minutes

* Customer Average Interruption Duration Index

Dominion Energy

Our Company

Distribution and Transmission

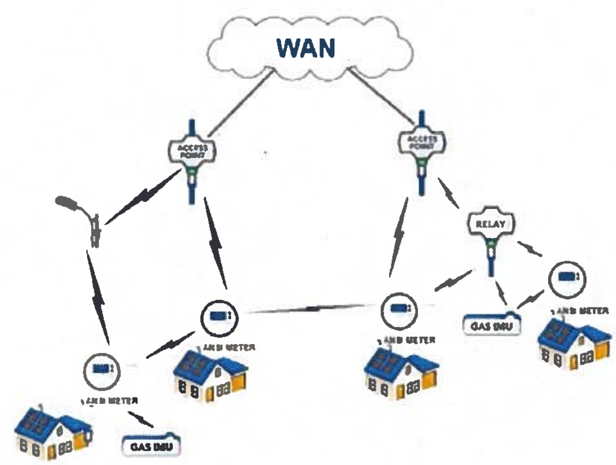
Modernization through Advanced Metering Infrastructure ("AMI")

In 2019, DESC committed to implement AMI technology for all electric meters on its system. AMI meters create a meter-to-meter communication grid that then connects to public wireless networks to provide full two-way communications between customers and the Company.

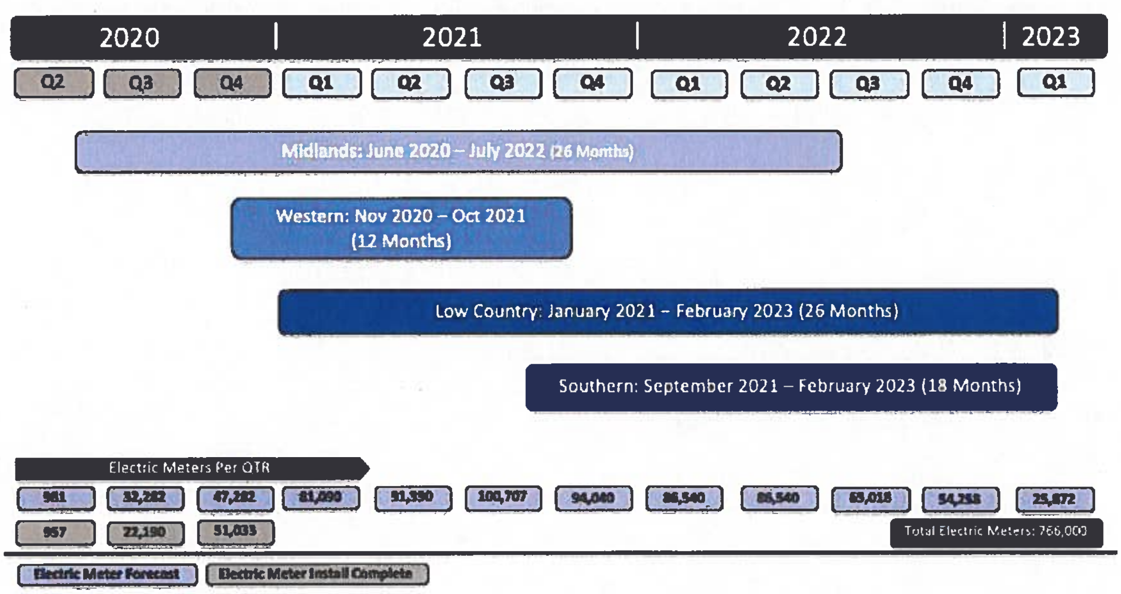
Meter readings and load profile interval data are remotely collected daily from all AMI meters. In addition to traditional metering functions, the technology also provides real-time monitoring capability including power outage/restoration, meter/site diagnostics, and power quality monitoring. Energy data is made available to customers daily via web applications, allowing customers to better manage energy consumption. AMI meters will allow DESC to offer demand response, demand shifting, and demand shedding programs to all customer classes.

Meter installations started in 2020 with 74,180 electric smart meters installed through the end of 2020. Installations continue ranging between 12,000 to 36,000 meters installed per month, throughout the end of the three-year installation period. Estimating customer growth, the final AMI electric meter count will be approximately 800,000 in March 2023.

Itron GenX Network



Projected AMI Installation



Responding to the Requirements of Integrating Distributed Generation

DESC's existing electric infrastructure, standards, and operating protocols have all been designed around a fully dispatchable generation fleet characterized by large centralized plants with high MW ratings. These plants are typically located on central transmission corridors. They are often connected to switchyards that serve as major transmission hubs. This allows power to flow from them in multiple directions. This configuration of resources maximizes the ability of system operators to manage power flows across the system and control system frequency and voltage effectively.

Incorporating distributed, non-dispatchable, intermittent generation onto the grid requires an on-going reassessment of all levels of electric infrastructure, standards, and operating protocols. As distributed renewable generation proliferates in the system, issues surrounding voltage control and load flows are being identified and factored into planning for maintaining reliability and future grid stability. The Company intends to monitor the penetration of electric vehicles on its system and ascertain the scope and timing of any distribution system upgrades required to accommodate the resulting demands placed on its distribution system. The results of these assessments and evaluations will inform future IRPs.

Transmission Plans and Planning

DESC's transmission planning function provides for timely modifications to the DESC transmission system to ensure a reliable and economical delivery of power as customer demands evolve, new generation and transmission is sited, and power flows on neighboring utilities change. The transmission planning group constantly evaluates the capability of DESC's transmission network to operate reliably under current conditions and over a ten-year planning horizon considering forecasted load growth, future additions and modifications to the transmission and generation system, and changes in power flows from adjacent systems.

Annual Transmission Assessments

DESC evaluates the current and future reliability of DESC's transmission system under mandatory Reliability Standards for Transmission Planning (the "Reliability Standards"). These standards are issued by the North American Electric

Leeds Avenue Solar Facility; North Charleston, South Carolina.

Reliability Corporation (NERC) in its capacity as the designated Electric Reliability Organization (ERO) under the Federal Energy Policy Act of 2005. DESC's transmission planning culminates each year in an Annual Transmission Assessment that is provided to NERC for review and audit and is provided to adjacent utilities for incorporation into the modeling of their systems.

As designated ERO, NERC may recommend and FERC may impose penalties of over $1.3 million per occurrence for any violation of mandatory planning or other reliability standards. FERC may also preempt action by state entities that compromises the reliability of the electrical system under its jurisdiction.

Each proposed change in DESC's generation or transmission system is evaluated for impacts over the ten-year planning horizon. DESC's power flow models are updated continuously as each new generation interconnection agreement is signed and as the construction of new or upgraded transmission assets are authorized. The models are routinely updated to reflect loads from major new residential, commercial, industrial, and wholesale customers and changes in the load forecasts for customer demands generally. The power flow models always reflect the most current information available.

Dominion Energy

Our Company

Distribution and Transmission

DESC has developed and adheres to a set of internal Long-Range Planning Criteria that can be summarized as follows:

> *[T]he system is designed so that during any of the following contingencies, only short-time overloads, low voltages and local loss of load will occur and that after appropriate switching and re-dispatching, all non-radial load can be served with reasonable voltages and that lines and transformers are operating within acceptable limits.*
>
> *a. Loss of any bus and associated facilities operating at a voltage level of 115kV or above*
>
> *b. Loss of any line operating at a voltage level of 115kV or above*
>
> *c. Loss of entire generating capability in any one plant*
>
> *d. Loss of all circuits on a common structure*
>
> *e. Loss of any transmission transformer*
>
> *f. Loss of any generating unit simultaneous with the loss of a single transmission line*

DESC assesses and designs its transmission system to be compliant with the requirements as set forth in these criteria and Reliability Standards. A copy of the NERC Reliability Standards is available at the NERC website www.nerc.com.

The DESC transmission system is interconnected with Duke Energy Progress, Duke Energy Carolinas, Santee Cooper, Georgia Power ("Southern Company") and the Southeastern Power Administration ("SEPA") systems. DESC participates with other transmission planners throughout the southeast to develop current and future power flow, stability and short circuit models of the integrated transmission grid for the NERC Eastern Interconnection. All participants' models are merged together to produce current and future models of the integrated electrical network. Using these models, DESC evaluates its current and future transmission system for compliance with the DESC Long Range Planning Criteria and the NERC Reliability Standards. As a result of these assessments, DESC has identified the following electrical transmission investments as required on its system.[5]

Planned Project	Tentative Completion Date
Church Creek – Faber Place 230kV & 115kV: Rebuild the Ashley River Crossing	May-21
Graniteville #2 – Toolebeck 115kV: Upgrade to 1272	May-21
Williams Street – Park Street 115kV: Construct	Jun-21
Saluda Hydro – Denny Terrace & Lake Murray – Harbison	Oct-21
Queensboro – Ft Johnson 115kV Tap	Dec-21
Bluffton – (SCPSA) Bluffton 115kV Tie Line Construct	Dec-21
Canadys 230kV: Add Back-to-Back Bus Tie Breakers	Dec-21
Canadys 230kV Sub: Reterminate Various Lines	Dec-21
Emory 230kV Distribution Sub: Construct	Dec-21
Graniteville #2 – South Augusta 230kV : Urq Jct – Toolbeck 230kV Fold In	Dec-21
Lex Westside – Gilbert 115kV Line	Dec-21
Batesburg – Ward 115kV Line	Dec-21
Trenton – Briggs Rd 115kV Line	Dec-21
Toolebeck Substation: Add three 230kV Terminals	Dec-21
Toolebeck – Aiken 230kV Tie: Construct	Dec-21
Cainhoy – Mt. Pleasant 115kV #1 and #2 (Horlbeck Creek Crossing)	Dec-21
Queensboro – Johns Island 115kV Tie: Rebuild River and Marsh Crossing	Dec-21
Edenwood Substation: Replace Switch House	Jun-22
Lake Murray – Gilbert 115kV Line	Dec-22
Burton – Yemassee 115kV #2 Line Rebuild as Double Circuit	Dec-22
Ward – Stevens Creek 115kV: Ward – Trenton Section Rebuild	Dec-22
Church Creek – Queensboro 115kV: Stono River Crossing	Dec-22
Denny Terrace – Crafts Farrow & Denny Terrace – Dentsville Line #1 115kV Rebuild	Dec-22
Wateree – Hopkins 230kV Line #2: Rebuild	Dec-22

[5] The projects listed above are the currently planned projects based on the latest assessment studies. The transmission expansion plan is continuously reviewed and may change due to changes in key data and assumptions. This summary of projects does not represent a commitment to build.

Dominion Energy

Our Company

Distribution and Transmission

Planned Project	Tentative Completion Date
Columbia Industrial Park – Kendrick 115kV & Columbia Industrial Park – Ft. Jackson #2 115kV: Rebuild	Dec-22
Stevens Creek – Ward – Lake Murray Line and Associated System Hardening Construct	Mar-23
Okatie – Bluffton 115kV: Rebuild	Dec-23
Denny Terrace Substation: Replace Switch House	Dec-23
Hopkins – Square D – Eastover 115kV: Rebuild	Dec-23
Burton – St Helena 115kV: Rebuild Burton – Frogmore Transmission Section and Frogmore Distribution – St Helena	Dec-23
VCS1 – Denny Terrace 230kV & VCS1 – Pineland 230kV: Rebuild Double Circuit Section and Single Circuit Sections	Dec-23
Wateree – Hopkins 230kV Line #1: Rebuild	Dec-23
Coit – Gills Creek 115kV Line: Construct	Dec-24
Union Pier 115–13.8kV Sub: Tap Construct	Dec-24
Cainhoy – Hamlin 115kV: Rebuild Line and Cainhoy – Hamlin 115kV #2: Construct New 115kV Line	Dec-24
Hopkins – CIP 230kV: Rebuild	Dec-24
Faber Place – Bayfront 115kV: Rebuild North Bridge Terrace to Bayfront Section	Dec-24
Wateree – Killian 230kV: Rebuild	Dec-25
Canadys – Ritter 115kV: Rebuild as 230/115kV Double Circuit	Jun-26
Lakeside 230–115kV Sub and the Jasper – Yemassee Fold In	Dec-26
Ritter – Yemassee 230kV and 115kV Transmission System Expansion	Jun-27
Clements Ferry 115–23kV Sub: Construct; Jack Primus–Cainhoy 115kV with Clements Ferry Tap Construct	Dec-27

Regional Transmission Planning

To assess the reliability of the wide-area integrated transmission grid, DESC participates in assessment studies with neighboring transmission planners throughout the southeast to assess the reliability of the southeastern integrated transmission grid for the long-term horizon (up to 10 years) and for upcoming seasonal (summer and winter) system conditions.

The following is a list of joint studies with neighboring transmission planners completed over the past year:

1. SERC Reliability Corporation ("SERC") Near Term Study Group Reliability 2019 Summer Study
2. SERC Near Term Study Group Reliability 2019/2020 Winter Study
3. SERC Near Term Study Group Open Access Same-time Information System ("OASIS") 2019 January Studies (19Q1)
4. SERC Near Term Study Group OASIS 2019 April Studies (19Q2)
5. SERC Near Term Study Group OASIS 2019 July Studies (19Q3)
6. SERC Near Term Study Group OASIS 2019 October Studies (19Q4)
7. SERC Long Term Study Group 2024 Future Year Study
8. Carolinas Transmission Coordination Arrangement 2021 Daytime Minimum, 2022 Daytime Minimum, 2024 Summer Peak – Reliability and Transfer Capability Studies
9. South Carolina Regional Transmission Planning 2020 Summer and 2023/24 Winter Transfer Studies

These activities, as discussed above, provide for a reliable and cost-effective transmission system for DESC customers and comply with Federal regulations.

Interconnection-wide Planning

DESC is an active member of the Eastern Interconnection Planning Collaborative ("EIPC"), which seeks to identify projects that will increase reliability, reduce costs and further reliance on renewable and intermittent resources by expanding the ability to transmit power between regions. EIPC was initiated by a coalition of NERC regional Planning Authorities (including DESC) that represent 95% of the Eastern Interconnection and spans from the maritime provinces of Canada through Florida and the mid-West.

EIPC provides a grass-roots approach which builds upon the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities. This approach provides coordinated interregional analysis for the entire Eastern Interconnection.

EIPC models the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. This work builds upon local and regional transmission planning processes. EIPC provides an interconnection-wide review of the existing regional plans and development of transmission options associated with the various policy options which includes maximizing the potential of renewable and non-emitting resources.

2019 Transmission Construction Projects

In 2019, DESC completed a number of major transmission construction projects. The **AMWilliams to Cainhoy Transmission Project** was required to meet load growth in Charleston and Mt. Pleasant through construction of the new 230 kV/115 kV Cainhoy Substation as well as twenty-five miles of new or rebuilt 230 kV and 115 kV transmission lines crossing both the Wando and Cooper Rivers. This project also hardened the transmission system in a high growth, coastal corridor by replacing existing, highly vulnerable wooden structures with steel monopoles that can endure wind speeds up to 150 mph. The sensitive environmental conditions required a carefully planned and executed construction effort.

Williams to Cainhoy Line Construction.
(During Construction, Looking West from the Cooper Crossing)

Williams to Cainhoy Line Construction.
(Post-Construction, Looking East Towards the Cooper Crossing)

In 2019, DESC completed the **Yemassee to Burton 115 kV #2 and #3 Lines** to serve growing loads in the Beaufort area. The new line replaced the approximately 70-year-old Yemassee to Burton #2 115 kV wooden transmission line with a modern double circuit line with a distribution line on the same structures.

Other recent load related transmission projects include the following:

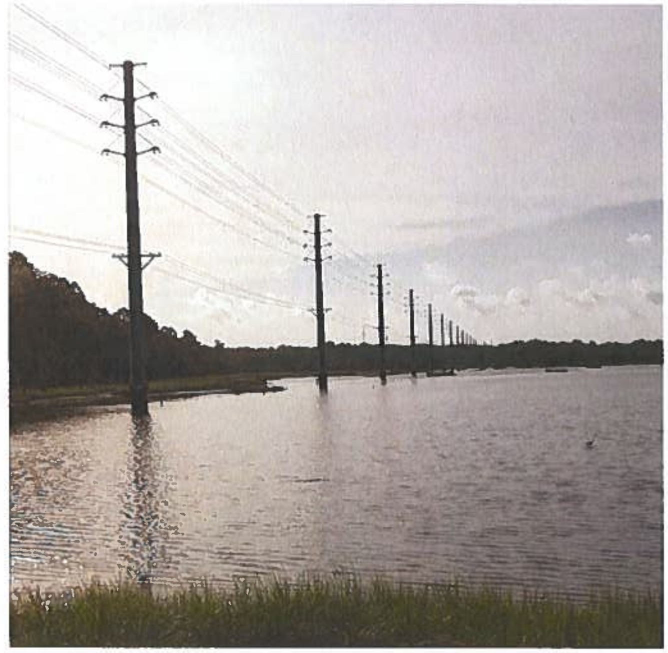
Sewee 115/23 kV Substation, Fold-In & Tie to CEPCI. Working in collaboration with Central Electrical Power Cooperative, DESC received a new point of service into its Sewee Substation near the intersection of Highway 17 and Lieben Road in Mt. Pleasant, South Carolina to improve reliability and accommodate the growing energy needs within this area.

Saxe-Gotha Industrial Park, 115-23 kV. DESC constructed this new substation to meet the growing electric demand in Cayce, South Carolina. This area is poised for developing residential growth along the 12th Street corridor near Interstate 77 and is already home to Amazon and Nephron Pharmaceuticals.

Gills Creek 115-23 kV and Fold-In. DESC constructed a new substation off Rosewood Drive to serve growing residential and commercial customers down Devine Street and Garners Ferry Road. This substation contains a new 28 MVA transformer and three 23 kV breakers.

Mercedes-Benz Vans 115 kV Substation Construction and 115 kV Fold-In. During 2019, DESC built a new DESC-owned substation in Ladson, South Carolina and installed two 115/13.8 kV, 37 MVA transformers to serve the Mercedes-Benz Vans manufacturing facility. The work also involved a fold-in of the nearby Pepperhill to Summerville 115 kV #2 transmission line.

Argos 115-13.8 kV Substation. DESC relocated the 115 kV #1 tap serving Argos Cement in Harleyville to accommodate a plant expansion, built a new customer substation, Argos Cement Substation #3, and then installed a new 115 kV tap to the newly constructed substation.



Yemassee-Burton

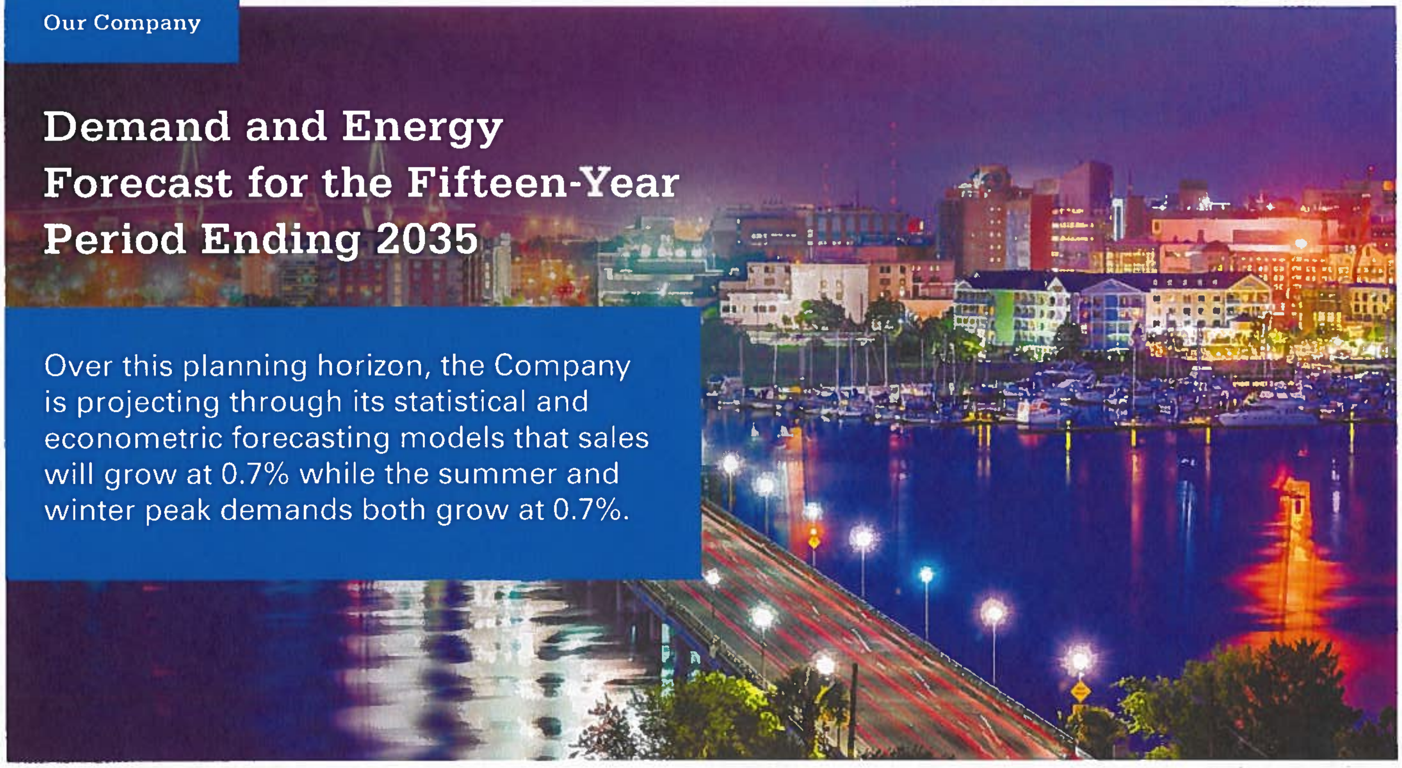
Jushi 115-13.8 kV Customer Substation. DESC relocated an existing 115 kV line and constructed a temporary line for a new industrial customer, Jushi, to utilize during construction. The customer is a new manufacturer of fiberglass material located in the Pineview Industrial Park in lower Richland County. Concurrently, DESC constructed a new customer substation and a 115 kV fold-in with redundancy to serve this customer's manufacturing plant.

Hugh Leatherman 115-13.8 kV Substation. DESC is designing and engineering a new 115 to 13.8 kV substation to serve the Hugh Leatherman shipping terminal at the South Carolina State Ports Authority in Charleston. This new shipping terminal is expected to boost port capacity by fifty percent. DESC will also construct a new 115 kV tap to feed this substation, necessary for additional cranes, buildings, high mast lighting, and other electrical supporting infrastructure.

Our Company

Demand and Energy Forecast for the Fifteen-Year Period Ending 2035

Over this planning horizon, the Company is projecting through its statistical and econometric forecasting models that sales will grow at 0.7% while the summer and winter peak demands both grow at 0.7%.



Charleston, South Carolina

DESC's Annual Energy Sales and Peak Demand by Season

The following table shows the Company's annual sales and its gross peak demand, i.e., its total internal demand, by season over the next fifteen years.

Annual Energy and Peak Forecast

Year	Annual	Peak Demand	
	Sales GWh	Summer MW	Winter MW
2021	23,937	4,814	4,939
2022	24,034	4,855	4,975
2023	24,215	4,893	5,002
2024	24,348	4,915	5,008
2025	24,403	4,918	5,037
2026	24,555	4,939	5,065
2027	24,696	4,965	5,094
2028	24,807	4,987	5,117
2029	24,934	5,003	5,139
2030	25,042	5,021	5,193
2031	25,274	5,079	5,251
2032	25,539	5,137	5,305
2033	25,843	5,194	5,360
2034	26,137	5,255	5,414
2035	26,460	5,312	5,467

Dominion Energy

Our Company

Demand and Energy Forecast for the Fifteen-Year Period Ending 2035

Over this planning horizon, the Company is projecting through its statistical and econometric forecasting models that sales will grow at 0.7% while the summer and winter peak demands both grow at 0.7%. The following two tables show the Company's projected demand response capacity and the resulting net firm peak demand, i.e., net internal demand, by season. The net firm peak demand in summer and winter are projected to grow at 0.7%.

Net Firm Peak Demand

Year	Demand Response		Net Firm Peak	
	Summer MW	Winter MW	Summer MW	Winter MW
2021	226	223	4,588	4,716
2022	227	225	4,628	4,750
2023	228	227	4,665	4,775
2024	229	229	4,686	4,779
2025	230	233	4,688	4,804
2026	231	238	4,708	4,827
2027	232	248	4,733	4,846
2028	233	260	4,754	4,857
2029	234	274	4,769	4,865
2030	235	275	4,786	4,918
2031	236	276	4,843	4,975
2032	237	277	4,900	5,028
2033	238	278	4,956	5,082
2034	239	279	5,016	5,135
2035	240	280	5,072	5,187

Note: Winter season follows summer.

Economic Scenario Analysis

The Company analyzed the sensitivity of its sales growth rate as required by § 58-37-40(B)(1)(a) under Act No. 62. The forecasted growth rate in sales over the 15-year IRP planning horizon of 2021-2035 is 0.7%. To develop a low growth scenario, DESC analyzed the first time it experienced a 15-year negative growth rate, which was in 2019, with a compounded annual growth rate of (0.1) %. During the period 2004-2019, DESC lost several wholesale customers. When the growth rate is adjusted for this unusual loss, the growth rate increases to 0%. Given that the State of South Carolina has experienced strong economic growth in recent years, a growth rate of 0% over the long term is highly unlikely. Therefore, a slightly higher growth rate was assumed in the low growth scenario. The low growth rate is 0.25%. For the high growth scenario, DESC analyzed its growth rate experience prior to the Great Recession which occurred from December 2007 through June 2009. The 15-year growth rates experienced by the Company during this period included a high of 3.4% and a low of 2.7% occurring just prior to the recession, i.e., over the period 1992-2007. When analyzing the detail behind the 2.7% growth rate, the residential and commercial customer growth rates were unusually high, due in part to the housing bubble leading to the recession. Also, the growth in wholesale sales was unreasonable as a proxy for the future because of changes in that class. When the 2.7% was adjusted for these components, the growth rate dropped to 1.7% and was selected as the high growth rate for this scenario analysis. While it is certainly true that DESC's sales could grow less than the low rate of 0.25% or more than the high rate of 1.7%, these rates represent reasonable ranges for the sales forecast. The changes in sales and peak demands from the base case that result are shown in the following tables.

High Economic Scenario

Year	Annual	Peak Demand	
	Sales GWh	Summer MW	Winter MW
2021	0.0	0.0	0.0
2022	234.2	47.3	48.5
2023	474.3	95.8	98.0
2024	718.9	145.1	147.9
2025	965.4	194.6	199.3
2026	1,220.2	245.4	251.7
2027	1,479.9	297.5	305.2
2028	1,742.8	350.4	359.5
2029	2,011.8	403.7	414.6
2030	2,284.3	458.0	473.7
2031	2,574.2	517.3	534.8
2032	2,875.5	578.4	597.3
2033	3,190.0	641.1	661.6
2034	3,512.4	706.2	727.6
2035	3,848.4	772.6	795.1

Note: Winter season follows summer.

Low Economic Scenario

Year	Annual	Peak Demand	
	Sales GWh	Summer MW	Winter MW
2021	0.0	0.0	0.0
2022	-111.8	-22.6	-23.1
2023	-224.7	-45.4	-46.4
2024	-338.1	-68.2	-69.5
2025	-450.7	-90.8	-93.0
2026	-565.6	-113.8	-116.7
2027	-681.1	-136.9	-140.5
2028	-796.3	-160.1	-164.3
2029	-912.6	-183.1	-188.1
2030	-1,028.7	-206.3	-213.3
2031	-1,151.0	-231.3	-239.1
2032	-1,276.4	-256.7	-265.1
2033	-1,405.7	-282.5	-291.6
2034	-1,536.7	-309.0	-318.3
2035	-1,671.5	-335.6	-345.3

Note: Winter season follows summer.

Wholesale Sales Scenario Analysis

Dominion Energy

Demand and Energy Forecast for the Fifteen-Year Period Ending 2035

Wholesale energy sales represent about 3.6% of the Company's total sales. Wholesale customers are served by the Company through negotiated long-term power supply contracts. For periods of time beyond the terms of the existing long-term power supply contracts, the Company must compete with other power suppliers for the wholesale customers' business. The Company plans to successfully renew these contracts with current customers and has included the load in its forecast. The table below shows the level of sales and peak demand attributed in its forecasting process to the Company's wholesale business in its base forecast.

Annual Wholesale Forecast			
Year	Annual	Peak Demand	
	Sales GWh	Summer MW	Winter MW
2021	871	148	147
2022	871	148	148
2023	875	149	149
2024	879	150	150
2025	883	150	151
2026	887	151	151
2027	892	152	152
2028	896	153	153
2029	899	154	154
2030	903	154	154
2031	907	155	155
2032	911	156	156
2033	917	157	157
2034	922	158	158
2035	928	159	160
Note: Winter season follows summer.			

Electric Vehicle Scenario Analysis

Electric vehicles have become more common as technology and customer desires change. Various automotive original equipment manufacturers ("OEMs") have released more EV models for sale to the public in the Company's service territory. While the overall penetration of EVs has been somewhat low, recent registration data from the South Carolina Department of Motor Vehicles ("DMV") demonstrates steady growth with a total of 4,145 electric vehicles registered in the state as of mid-year 2019, compared to 2,652 in mid-year 2018 (50% growth rate).

The following table shows an estimate of the number of registered vehicles in DESC's territory. It assumes 2.1 vehicles per household applied to the DESC's residential customer forecast. A distinction is not made between two types of EVs: battery electric vehicles ("BEV") and plug-in electric vehicles ("PHEV"). PHEVs run on both electricity and gasoline. Two scenarios are defined: the base case and the high case. The base case is included in the Company's sales forecast shown above and it assumes an EV market share of about 2.9% by 2035. The high case represents how the EV market might develop perhaps under regulatory support and it assumes an EV market share of about 24% by 2035.

EV Growth Scenarios			
Year	Vehicles	Base Case	High Case
2021	1,383,648	2,214	2,214
2022	1,407,838	3,348	9,824
2023	1,427,084	4,503	17,632
2024	1,443,918	5,679	25,605
2025	1,460,304	6,880	33,749
2026	1,478,180	8,114	42,112
2027	1,496,273	9,377	50,674
2028	1,513,789	10,664	59,408
2029	1,530,696	11,973	68,303
2030	1,547,385	13,308	77,369
2031	1,565,775	19,948	137,788
2032	1,583,824	26,735	199,562
2033	1,601,515	33,664	262,648
2034	1,619,115	40,737	327,061
2035	1,636,335	47,945	392,720

An approximation of the amount of electric power these EVs will need can be calculated by assuming two quantities: the number of miles driven each year, i.e., 15,000 miles and the number of miles per kWh required, i.e., 4 miles per kWh. The following table shows the results of these assumptions on energy sales over the IRP planning horizon. Customers on the DESC system require about 25,000 GWh per year, so in the early years serving these EV sales will not require an immediate adjustment to the resource plan. To derive a summer peak MW demand, a system coincident load factor of 33% was assumed. The following table shows the results of this assumption. A winter peak MW demand is not shown because it is assumed that there will be little or no EV charging at 8:00 am on winter mornings when the Company's system experiences its peak demand.

EV GWh Sales		
Year	Base Case	High Case
2021	9.0	9.0
2022	13.6	39.8
2023	18.2	71.4
2024	23.0	103.7
2025	27.9	136.7
2026	32.9	170.6
2027	38.0	205.2
2028	43.2	240.6
2029	48.5	276.6
2030	53.9	313.3
2031	80.8	558.0
2032	108.3	808.2
2033	136.3	1,063.7
2034	165.0	1,324.6
2035	194.2	1,590.5

EV Summer MW Peak		
Year	Base Case	High Case
2021	3	3
2022	5	14
2023	6	25
2024	8	36
2025	10	47
2026	11	59
2027	13	71
2028	15	83
2029	17	96
2030	19	108
2031	28	193
2032	37	280
2033	47	368
2034	57	458
2035	67	550

There are four other EV markets to consider: transit buses, school buses, off-road vehicles and commercial fleet vehicles. Charleston Area Regional Transportation Authority has placed 3 Proterra transit buses in service as of January 2020 with 3 more being delivered in January 2021. Each bus will require an estimated 80,000 kwh per year and a peak demand of 125 KW.

DESC expects EVs to have the largest initial impact on distribution systems in urban growth areas. Although much of the DESC service territory is rural, the Charleston Metropolitan area is already seeing EV growth. The overall demographics, DESC's partnership with the Charleston Area Regional Transportation Authority, and plans by private entities to add larger more robust charging stations in the

CARTA electric bus system; Charleston, South Carolina.

Charleston area and along major transportation corridors in South Carolina are helping EV growth. The Company anticipates the strong growth in urban Charleston will continue to gain strength. This year will be a pivotal year for EV sales with 40 models of plug-in EVs already offered, and 14 newer and more attractive models being introduced for 2020. As battery prices are decreasing and driving down the cost of EVs, they will appeal to a broader cross section of South Carolina customers. Like Charleston, adoption rates are expected to increase in markets like Columbia, Hilton Head and Aiken. The local distribution impacts will certainly require additional planning and investments. A single Tesla supercharger charging bay has a maximum rated output of 250 kW (350 kW stand-alone), which is almost 40 times that of a residential water heater. Commonly arranged in eight charging bays, the supercharger station could demand 1 MW of new load in a single location. Urban distribution systems will need automation and hardening in the next few years.

Current indications are that the EV market will develop more rapidly than previously forecasted. Battery technology is advancing steadily. Major automotive manufacturers have announced plans to transition their fleets to focus on EV vehicles in the relatively near term. The Biden Administration has indicated that it intends to use regulatory levers and incentives to increase the penetration of EV vehicles in the US market as part of its climate goals. DESC's EV forecasts will be updated to reflect the evolving market and regulatory situation in future IRP updates.

Our Company

Demand Side Management

DSM programs seek to influence the level and timing of the consumption of energy by customers.

DSM programs seek to influence the level and timing of the consumption of energy by customers. The two principal subsets of DSM are EE and Load Management (also known as Demand Response or DR). EE typically includes actions designed to increase the efficiency of lighting, appliances, equipment or buildings so that the same level of production or comfort can be achieved using less energy. Load Management typically includes actions designed to encourage customers to reduce usage during peak load hours or shift that usage to other times.

Energy Efficiency

DESC's EE programs include the portfolio of DSM Programs and Energy Conservation Rates. A description of each follows:

Demand Side Management Programs

Beginning in 2018, DESC, through independent third-party consultants, conducted a comprehensive potential study and DSM program analysis. By Order No. 2019-880, dated December 20, 2019, the Commission approved the suite of ten modified, expanded and new DSM programs, which was identified by the 2019 Potential Study, for the next five years beginning in 2020. Eight of these programs are an expansion or modification of existing programs, and two are new programs. The program impacts identified in the 2019 Potential Study have been updated following an avoided cost update in Docket No. 2019-184-E and include the reasonable and achievable results determined under the initial rapid assessment—per Order No. 2020-832—now the basis for the Medium DSM case in the Resource Plan Analysis. The portfolio includes seven (7) programs targeting DESC's residential customer classes and three (3) programs targeting commercial and industrial customers that have not opted out of the DSM rider. A description of each program follows:

The Residential Home Energy Reports Program provides customers with monthly/bi-monthly reports comparing their energy usage to a peer group and providing household information to help identify, analyze and act upon potential energy efficiency measures and behaviors. Initially, participants are solicited via direct-mail and e-mail campaigns under an opt-in approach. Based on the 2019 Potential Study, the program will shift to an opt-out model where customers whose usage levels indicate the greatest potential savings are automatically enrolled in the program unless they opt out. The program has completed the necessary activities to phase down participants in the opt-in model. The 2019 Potential Study forecasted this transition to occur by 2023, however, DESC is currently working with a new implementer to transition to the opt-out model in 2021.

The Residential Home Energy Check-up Program provides customers with a visual energy assessment performed by DESC staff at the customer's home. At the completion of the visit, customers are offered an energy efficiency kit containing simple energy conservation measures, such as energy efficient bulbs, water heater wrap and/or pipe insulation. The Home Energy Check-up (Tier 1) is provided at no additional cost to all electric residential customers who elect to participate. Due to the ongoing impacts of the COVID-19 pandemic, DESC has suspended in-home services and now offers a Virtual Home Energy Check-up. Per the results of the 2019 Potential Study, DESC began initial steps to implement a Tier 2 component. Tier 2 includes customer incentives for the installation of energy efficiency measures that aim to increase efficient operation of the house. Tier 2 implementation has been stalled due to the ongoing impacts of the COVID-19 pandemic.

The Residential EnergyWise Savings Store incentivizes residential customers to purchase and install high-efficiency ENERGY STAR® qualified lighting products by providing deep discounts directly to customers. In 2019, DESC continued to offer lighting incentives via an online store, in addition to providing energy efficiency lighting kits to customers at various business office locations, community events and via direct mail. New to the online store, DESC introduced smart thermostats to provide deeper heating and cooling savings to participants. This program transitioned to a new implementer in 2020.

The Residential Heating & Cooling Program provides incentives to customers for purchasing and installing high efficiency HVAC equipment in existing homes. Additionally, the program provides residential customers with incentives to improve the efficiency of existing air conditioning and heat pump systems through duct insulation and duct sealing. Per the results of the 2019 Potential Study, the program has increased heating and cooling equipment and duct work improvement rebate amounts to encourage participation. New rebates include heat pump water heaters and electric resistant heat to heat pump equipment replacement.

The Neighborhood Energy Efficiency Program ("NEEP") provides income-qualified customers with energy efficiency education and direct installation of multiple low-cost energy conservation measures as part of a neighborhood door-to-door sweep approach to reach customers. Additionally, the NEEP Program

Low cost, no cost measures like caulking can help customers manage their energy expenses.

continued offerings to mobile and manufactured homes to include weatherization measures specific to this housing stock. Per the results of the 2019 Potential Study, NEEP will increase customer participation by increasing the number of neighborhoods, increasing penetration into selected neighborhoods and selecting larger neighborhoods. The program was suspended due the ongoing impact of the COVID-19 pandemic. In the interim, using CDC safety guidelines, DESC has begun to distribute energy efficiency kits in qualifying neighborhoods. When the program resumes in-home services, it will do so under expanded guidelines to reach more customers. Neighborhoods will be selected on the basis of at least 50% of household incomes at or below 200% of the federal poverty guideline – up from 150%.

The Residential Appliance Recycling Program provides incentives to residential customers for allowing DESC to collect and recycle less efficient, but operable, secondary refrigerators, and/or standalone freezers, permanently removing the units from service. Per the results of the 2019 Potential Study, the program will focus on increasing participation through increased marketing and promotional events. In 2020, DESC introduced its "no contact" pick-up to allow customers the option of leaving units outdoors for pick-up using CDC safety guidelines to prevent the spread of COVID-19.

The Residential Multifamily Program focuses on helping customers living in non-single-family dwellings as well as apartment building owners and managers overcome the split-incentive and other market barriers to residential energy efficiency. The split incentive barrier exists in rental situations: non-occupant building owners are less inclined to make efficiency upgrades when they do not pay energy bills, and renters are less likely to make efficiency upgrades because they do not own their dwelling. The program will achieve this goal by directly installing LEDs and water-saving measures in apartments, and by providing high incentives for building common area measures, such as lighting and HVAC upgrades. Although the Neighborhood Energy Efficiency and Home Energy Check-up programs both include multifamily units, the specific targeting of multifamily properties is a new effort. DESC began initial implementation of this program in 2020 focusing on the common area retrofits only. In-unit installations have been suspended due to the impacts of the COVID-19 pandemic.

The EnergyWise for Your Business Program provides incentives to non-residential customers (who have not opted out of the DSM rider) to invest in high-efficiency lighting and fixtures, high efficiency motors and other equipment. To ensure simplicity, the program includes a master list of prescriptive measures and incentive levels that are easily accessible to commercial and industrial customers on DESC's website. Additionally, a custom path provides incentives to commercial and industrial customers based on the calculated efficiency benefits of their energy efficiency plans or new construction proposals. This program applies to technologies and applications that are more complex and customer specific. All aspects of this program fit within the parameters of retrofits, building tune-ups and new construction projects. Per the 2019 Potential Study, the program will increase customer participation and is in the process of implementing two new components: Agricultural and Strategic Energy Management.

The Small Business Energy Solutions Program is a turnkey program, tailored to help owners of small businesses manage energy costs by providing incentives for energy efficiency lighting and refrigeration upgrades. The program is available to DESC's small business and small nonprofit customers with an annual energy usage of 350,000 kWh or less, and five or fewer DESC electric accounts. Per the results of the 2019

The Small Business Energy Solutions Program provides small business owners incentives to help manage their energy costs.

Potential Study, DESC increased the incentive level from 80% of project costs to 90% (up to $6,000) to reduce the barrier to entry for small business customers.

The Municipal LED Lighting Program offers municipalities in the DESC service territory incentives to replace street lighting with high efficiency LED streetlights. The incentives allow for a financially neutral option for municipalities to convert while improving performance, providing remote monitoring/outage and better overall customer experience. This is a new program that DESC anticipates will be well received by municipalities.

Energy Conservation Rates

Energy conservation is a term that has been used interchangeably with energy efficiency. However, energy conservation has the connotation of using less energy in order to save rather than using less energy to perform the same or better function more efficiently. The following is an overview of each DESC energy conservation rate:

Energy Saver/Conservation Rate: Rate 6 (Energy Saver/Conservation) rewards homeowners and homebuilders with a reduced electric rate when they upgrade existing homes or build new homes to a high level of energy efficiency.

Seasonal Rates: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

Load Management Programs

The primary goal of DESC's load management programs is to reduce the need for additional generating capacity. There are four existing load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. A description of each follows:

The Standby Generator Program: The Standby Generator Program for wholesale customers provides about 27 MW of peaking capacity that can be called upon when reserve capacity is low on the system. This capacity is owned by DESC's wholesale customers and is made available to DESC System Controllers through contractual arrangements. DESC has a retail version of its standby generator program in which DESC can call on participants to run their emergency generators. This retail program provides approximately 10 MW of additional capacity when called upon.

Interruptible Load Program: DESC has over 200 megawatts of interruptible customer load under contract. Participating industrial customers receive a discount on their demand charges in exchange for shedding load when DESC is short of capacity.

Real Time Pricing ("RTP") Rate: A number of customers receive power under DESC's real time pricing rate. During peak usage periods throughout the year when capacity availability is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Alternatively, during high capacity availability periods, prices are lower.

Time of Use Rates: DESC's time of use rates contain higher charges during the peak usage periods of the day and lower charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All DESC customers have the option of purchasing electricity under a time of use rate.

An investigation of winter peaking programs was performed as part of the 2019 Potential Study. DESC, through independent third-party consultants, modeled a suite of new direct load control and other measures for residential and commercial customers that would rely on AMI being installed. Within the five-year program planning cycle, none of these new DR programs were found to be cost-effective and thus none were pursued further due to the cost of installing AMI as a DSM program expense. However, the 2019 Potential Study showed that a rollout of AMI system-wide outside of the DSM context would support additional expansion of these DR programs. The study indicated that, with a sufficient saturation of AMI in place, Time of Use and Critical Peak Pricing could be cost effective. In absolute terms, by winter 2029, an additional 43 MW in peak demand reduction could be achieved. Program plans will be assessed as the installation of AMI meters reaches an appropriate level of saturation and can support cost-effective DR programs.

DSM Rapid Assessment

Order No. 2020-832 required that "DESC work with the DSM [Energy Efficiency] Advisory Group to conduct a rapid assessment of the cost-effectiveness and achievability of ramping up its current DSM portfolio, such as by expanding programs or increasing spending, to achieve at least a 1% level of savings in the years 2022, 2023, and 2024" for inclusion in this Modified 2020 IRP.

On January 19, 2021, DESC met with its Energy Efficiency Advisory Group ("EE Advisory Group") to receive input on the initial outcomes of the rapid assessment and to discuss suggestions arising from the IRP proceeding, specifically, suggestions offered by Dr. David Hill on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Overall, ICF International, Inc. ("ICF") concluded that three of Dr. Hill's recommendations were both reasonable and achievable and should be included in the rapid assessment. These recommendations were

1. Increase outreach to approximately 54,000 units for the Municipal Lighting Program; and
2. Double participation in the Neighborhood Energy Efficiency Program; and
3. Move to an opt-out delivery model for Home Energy Reports earlier, in 2021.

These recommendations, along with an analysis of other possible measures, were included in the initial rapid assessment with an outcome of 0.73% reduction in retail sales. During the meeting, ICF provided detailed explanations for why the other recommendations from Dr. Hill were not included and also responded to numerous questions and suggestions for additional program expansions.

Present at the January 19, 2021 meeting, not including DESC personnel, were representatives of:

- Southern Alliance for Clean Energy
- Energy Futures Group
- SC Office of Economic Opportunity
- SC Small Business Chamber of Commerce
- Coastal Conservation League
- SC Association of Community Action Partnerships
- SC Office of Regulatory Staff
- SC Energy Office
- ICF

Following the meeting, further input from the EE Advisory Group was encouraged through January 26, 2021, to be considered in the final version of the rapid assessment, where possible.

DESC asked ICF to determine in the final version of the rapid assessment if a suite of programs resulting in a near term reduction in retail sales of 1% could be achieved. The results concluded that, though individual programs' results may not remain cost effective, at the portfolio level the suite of programs did remain cost-effective and would be achievable near term. This final assessment was not concluded in time for specific data to be included in the IRP modeling in this filing. However, a DSM scenario representing a 1% retail sales reduction was assumed as the Expected DSM High Case before the rapid assessment was complete. The results of the Final High Case Rapid Assessment are attached as **Appendix D.**

The final rapid assessment report took into consideration recommendations from Dr. Hill in his Late Filed Exhibit, extensive feedback and recommendations from the EE Advisory Group, DSM staff recommendations and program experience, emerging new technologies, rate-based programs and the extensive knowledge and expertise of ICF to determine a portfolio of programs in support of a 1% High Case. A summary of the outcomes from the recommendations is described within the report. In the final analysis, ICF determined that there is a path for DESC is achieve 1% savings in retail sales in years 2022, 2023 and 2024.

A three-month long "rapid assessment" of program recommendations cannot replicate the types of in-depth analysis contained in a potential study. DESC is beginning the process for a comprehensive evaluation in the form of a DSM potential study.

Action Plan for Comprehensive DSM Evaluation

Order No. 2020-832 also required the Company to develop an action plan to complete a comprehensive DSM evaluation of the cost-effectiveness and achievability of DSM portfolios reaching 1% and higher savings, including savings levels of 1.25%, 1.5%, 1.75% and 2% for inclusion in its next full IRP, to be filed in 2023.[6] DESC intends to complete this evaluation by initiating a new potential study in early to mid-2021. DESC will include the EE Advisory Group in the process of scoping of the study and will provide opportunities for iterative review, input and feedback. New to the EE Advisory Group for this process are the Energy Futures Group, an environmental group, and the SC Association of Community Action Partnerships, which represents low income residents. The current timeline is as follows:

1. No later than Q3 2021: Select vendor and initiate potential study for the 2023 IRP.
2. No later than Q4 2021: Hold kick-off meeting with EE Advisory Group to discuss scope and process for potential study.
3. 2022: Provide EE Advisory Group with status reports during regularly scheduled meetings at least twice per year. Provide both the EE Advisory Group and the IRP Stakeholder Advisory Group with final draft for input prior to finalization of potential study.
4. 2023: Incorporate potential study findings in 2023 IRP. The 2023 IRP shall include incentive options and best practices to achieve the modeled levels of DSM.

[6] DESC would note that Order No. 2020-832 inconsistently provides both a 2022 and 2023 deadline for the comprehensive DSM evaluation. Given that the next full IRP is to be filed in 2023, DESC assumes that the 2023 deadline applies, and the 2022 deadline was misstated. Additionally, to complete a comprehensive DSM evaluation with stakeholder involvement, 2023 is the most practical deadline.

Our Company

Renewables

DESC has 973 MW-AC of solar capacity currently under executed PPAs.

Springfield Solar Facility; Orangeburg, South Carolina.

Renewable Energy by Year (Existing PPAs Only)	
Year	**GWh**
2020	1,541
2021	1,859
2022	2,015
2023	2,034
2024	2,034
2025	2,034
2026	2,029
2027	2,032
2028	2,042
2029	2,032
2030	2,032
2031	2,034
2032	2,036
2033	2,034
2034	2,034

Renewable Power from Solar

DESC currently has 973 MW-AC of solar capacity under executed PPAs.

Ten of the fourteen resource plans evaluated in the Modified 2020 IRP assumed the addition of large blocks of renewable resources in the form of solar and solar plus battery storage. Of those plans, RP8 assumes the greatest reliance on solar generation over the long term. It forecasts that solar generation during the last five years of the forty-year period will total 28,502 GWh. This is nearly three times the renewable generation forecasted to be generated during that period under RP1 through RP4, and nearly double the amount of renewable generation envisioned under RP5, RP6, RP7 and all scenarios under RP7a and RP7b.

This level of solar generation will pose operating challenges to the system. The loss of solar generation is nearly instantaneous when cloud cover extends over a solar farm. To compensate, the Company must have dispatchable supply-side resources with quick start times and fast ramp rates to respond. Examples of these resources include pumped storage, batteries and quick-start internal combustion turbines.

In addition, solar generation is out of sync with winter peaks (which occur in the early morning hours) and only partially in sync in summer peaks (which occur as the sun begins to set). Sufficient amounts of energy storage and dispatchable generation will be required to cover these peak demand periods.

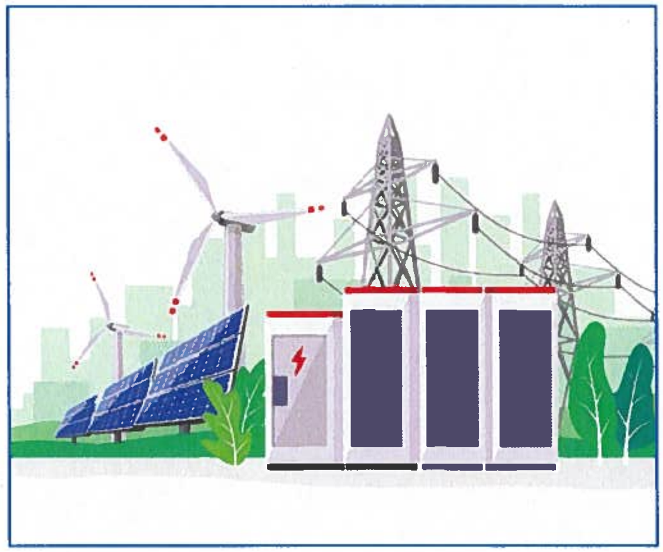
In a low-carbon future, weather patterns involving several cold and cloudy days in a row will pose a particular issue for meeting winter peaks reliably. A cost-effective strategy must be in place to replace renewable energy during these events and to recharge battery storage during an extended period without energy from solar generation.

Research, innovation and careful planning of system operations will be required to ensure continued reliable service to customers possible with reliance on solar generation at this level. Technical advances must be made with regard to energy storage costs and reliability, and perhaps hydrogen-fueled quick-start generation, all in conjunction with changes in grid operations and flexible operating technologies. The incremental implementation of solar and storage technology in the coming years will allow the electric grid to adapt to operational impacts in a cost-effective manner.

Cogeneration/Combined Heat and Power

Cogeneration and combined heat and power projects are projects undertaken in partnership with customers who have a need for significant quantities of heat (generally in the form of steam or hot water) for space heating for major facilities, for greenhouses or for industrial processes. In these projects, generation resources are sited at the customer's location to provide heat while at the same time generating electricity for the grid. These projects are highly dependent upon the customer's individual heat requirements and therefore are impossible to accurately model as a generic project for future implementation. Customers can best be approached to partner in such projects at the time a specific generation need is being considered on the system.

The Company is open to other forms of customer-sited generation opportunities as well including siting generation assets to supply critical infrastructure during system emergencies at military installations, hospitals, universities, and major government facilities. Such distributed generation assets can also be used to support system needs as standby generation during system peak periods.



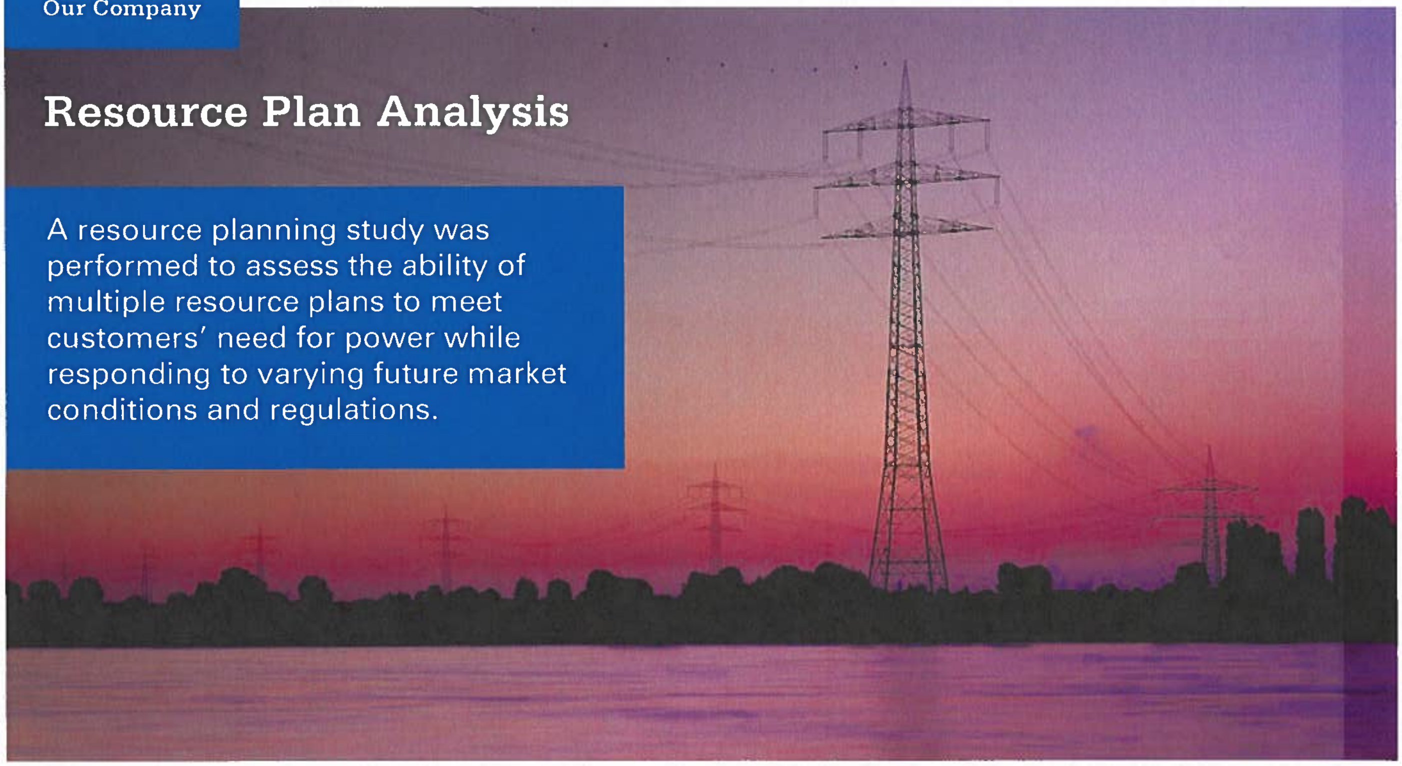
Energy Storage

Energy storage will be increasingly important to providing continued reliability for customers as the Company's renewable portfolio expands. The most practical energy storage technologies available today include hydroelectric pump storage and chemical batteries. Pump storage, like the existing 576 MW Fairfield Pump Storage Facility, requires specific land features (topography) and lengthy permitting. There are presently no future pump storage projects envisioned for DESC's system. At present, on DESC's system, battery storage is envisioned as the most effective near-term storage option to support renewable generation.

Battery storage allows the system to absorb excess solar generation during times of day when loads are light and to use that power to supply customer needs when load increases or when solar generation is otherwise unavailable. Six of the resource plans modeled in this IRP include battery storage as a resource to support solar generation. The modeling reflects the rapidly declining capital cost of battery storage projects. A comparison of the modeling results for RP7a 1-3 (which envisions solar without storage) and RP7b 1-3 shows that adding storage greatly increases the value to customers of incremental solar additions.

Dominion Energy

Our Company



Resource Plan Analysis

A resource planning study was performed to assess the ability of multiple resource plans to meet customers' need for power while responding to varying future market conditions and regulations.

Overview

This Resource Plan Analysis documents the ability of a diverse set of resource plans to meet customers' needs for power while responding to varying future market conditions and the Company's commitment to a clean and efficient energy future. In the previous 2020 IRP filing, eight resource plans were studied using three natural gas prices and two CO_2 cost scenarios and three DSM cases. In this Modified 2020 IRP, six plans proposed by the SCSBA were added at Commission direction for a total of fourteen plans. The fourteen plans were evaluated under the three levels of natural gas prices, three CO_2 emission cost prices, and three DSM cases—twenty-seven different sensitivities. The Company's base forecast of energy and demand has been updated for this analysis and is used as a starting point in developing the DSM scenario loads.

The expected case forecast is called the High DSM case. The High DSM case assumes that the Company is able to achieve a 1% reduction in load through its DSM programs. This change reflects the expectation that a cost-effective suite of DSM program can be formulated to reach a 1% reduction in load, even though individual programs or measures contained in the suite of programs may not be, on a standalone basis, cost effective.

The Medium DSM case is based on the expected program levels identified in the initial rapid assessment of the 2019 Potential Study. The low DSM case assumes that the Company achieves 90% of the DSM levels described in the 2019 Potential Study.

Resource portfolios were developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. The following pages provide data that highlight the key features of each resource plan in terms of cost, CO_2 emissions, renewable energy, fuel cost sensitivity and related metrics.

Reserve Margin

All plans were built to meet a minimum 21% winter reserve margin and a minimum 14% summer reserve margin as specified in Order No. 2020-832. A single integrated reserve margin was used for each season. A two-part margin was used in the initial 2020 IRP modeling.

Dominion Energy

Our Company

Resource Plan Analysis

Meeting the Base Resource Need

DESC created a list of seven generating resources to be used as building blocks in creating resource plans. The following table lists these resources. Not only are these resources indicative of the relevant technologies available, but each capacity/configuration was chosen with the DESC system characteristics in mind. Load growth rates in future years are anticipated to be modest. Even with retirements, relatively modestly-sized units at or below 500 MW are suitable for most circumstances in these plans. Given the size of DESC's system, even 100 MW additions have a significant physical and financial impact on this system. In addition, the resource plans either assumed that Wateree and Williams Stations were retired when they reached their end of useful life, which is in years 2044 and 2047 respectively, or were retired earlier, in 2028. In RP8, Cope Station was converted to gas-fired only status by 2030. Resource plans were also created to model the early retirement of older fossil-steam gas-fired units.

For candidate resources, the capital costs of the resources modeled in each plan have been escalated or de-escalated from 2020 to the year that the generator is installed. The installation year varies by resource plan to reflect the size of the increments of generation capacity that are added. In addition, even within a single resource plan, the installation year for resources varies based on the DSM sensitivities modeled because of the different levels of demand growth these DSM sensitivities assume. The capacity used in the resource plan schedule for CC and ICT resources is their winter capacity.

Available Resources	Capital Cost 2020 $/kW	Escalation Rate	Capacity	Source of Data
Annual Purchases	N/A	2%	50 MW	• Prior experience with market purchases • Gas is assumed to be the fuel at 11,700 heat rate, $1.54/MWh O&M costs, $4.5/kW-month capacity costs, $2400 start cost
Battery Storage	$1,349	Annual escalation per NREL 2020-ATB	100 MW with 4 hour duration	• Capex is from NREL Mid Technology Cost Scenario nominal forecast of CAPEX from 2019 Annual Technology Baseline • CAPEX Escalation is from NREL Advanced Technology Cost Scenario nominal forecast of CAPEX from 2020 Annual Technology Baseline
Solar	$1,151	Annual escalation per NREL 2020-ATB	50, 100 or 400 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from NREL Advanced Technology Cost Scenario nominal forecast of CAPEX from 2020 Annual Technology Baseline
CC 1-on-1	$1,406	3.75%	553 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
ICT Large Frame (2x)	$714	3.75%	523 MW	• U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2020 (AEO2020) • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
ICT Aero (2x)	$970	3.75%	131 MW	• Dominion Energy Services - Generation Construction Financial Management & Controls • CAPEX Escalation is from Handy Whitman July 2019 15 year Average – Total Plant
Solar PPA	N/A	N/A	400 MW	• NREL 2020, Advanced Technology Cost Scenario from 2020 Annual Technology Baseline • An integration charge of $0.96/MWh is added to the PPA price. • For RP7a and RP7b three costs were modeled as specified by Order No. 2020-832, $38.94/MWh, $36/MWh, $34/MWh

Resource Plans

A collection of generation resources and technologies was identified with the purpose of fairly evaluating a range of supply-side resources that are currently available to meet the utility's service obligations. These included:

- Storage
- Annual Power Purchase Agreement
- Utility-owned solar and third-party solar PPA
- CC and ICT gas turbine resources
- Reasonable scenarios for the early retirement of some generation facilities were also identified.

These resources and assumptions concerning facility retirements were combined into fourteen resource plans. Next a set of low, medium and high demand side scenarios was identified that included customer energy efficiency and demand response. The base load forecast combined with each of the three DSM scenarios created three forecasts of summer and winter peaks and annual utility energy sales.

Using the peak forecasts, the fourteen groups of resources were configured and resource additions were scheduled to ensure that DESC could meet its reserve margin requirements in summer and winter of each year. The scheduling of resource additions was determined by capacity needs on the system as they evolve in sequential years. These resulting schedules of resource additions produced the fourteen resource plans that were modeled. These fourteen resource plans covered a wide range of options. In all,

a. Three different retirement plans were modeled.

b. Ten plans included additional renewables.

c. All plans included 973 MW of existing solar PPAs.

d. RP8 included approximately 1,900 MW of solar and 700 MW of storage.

e. Three different sized solar generators were modeled at 400 MW, 100 MW and 50 MW.

f. Two different types of solar generation were modeled, Company-owned and third party owned PPAs.

g. Three different gas generators were modeled—CC, Frame ICT, and Aero ICT.

Description of Resource Plans

Resource Plan ID	Resource Plan Name	Resource Plan Description
RP1	CC	An initial Combined Cycle followed by large frame ICTs
RP2	ICT	Large Frame ICTs
RP3	Retire Wateree	Wateree 1 & 2 retirement (2028), Combined Cycle, large frame ICTs
RP4	Retire Steam Gas	McMeekin and Urquhart 3 retirement, large frame ICTs
RP5	Solar + Storage 2026	Flexible Solar + Battery Storage, Combined Cycle, large frame ICTs
RP6	Solar 2026	Flexible Solar, large frame ICTs
RP7	Solar PPA 2026 + Storage 2026	Flexible Solar PPA(400MW) + Battery Storage (100MW), large frame ICTs
RP7a	Solar PPA 2023	Flexible Solar PPA(400MW) $38.94/MWh + large frame ICTs
RP7a2	Solar PPA 2023	Flexible Solar PPA(400MW) $36/MWh + large frame ICTs
RP7a3	Solar PPA 2023	Flexible Solar PPA(400MW) $34/MWh + large frame ICTs
RP7b	Solar PPA 2023 + Storage 2023	Flexible Solar PPA(400MW) $38.94/MWh + Battery Storage PPA (100MW), large frame ICTs
RP7b2	Solar PPA 2023 + Storage 2023	Flexible Solar PPA(400MW) $36/MWh + Battery Storage PPA (100MW), large frame ICTs
RP7b3	Solar PPA 2023 + Storage 2023	Flexible Solar PPA(400MW) $34/MWh + Battery Storage PPA (100MW), large frame ICTs
RP8	Replace Coal with Gas and Renewables	Wateree and Williams retirements (2028) with Combined Cycle, Solar and Battery Storage, large frame and aeroderivative ICTs

Flexible solar is defined as a solar facility which can be curtailed when systems' conditions require and/or reinstated with system needs.

In each resource plan, three or four years of annual PPAs for firm capacity are typically added to meet the 21% reserve margin prior to building new gas generation. This serves to delay the need to build new capacity without compromising reliability and allows the new resource to be optimally utilized at the time of commissioning. In keeping with Order No. 2020-832, existing solar PPAs are credited with 11.8% summer and winter capacity while new solar is credited with 4.25% summer and winter capacity. See **Appendix F** for a discussion and calculation of solar Effective Load Carrying Capacity ("ELCC") required by Order No. 2020-832.

Resource plans RP7a, RP7a2, RP7a3, RP7b, RP7b2, RP7b3 were required by Order No. 2020-832 to assess the reasonableness of procuring solar generation via a solar PPA in 2023. These plans were proposed by the South Carolina Solar Business Alliance and envisioned adding renewable resources in time to earn a 22% Federal ITC, which was then anticipated to require construction to be started by 2021. In the H.R. 133, the Consolidated Appropriations Act, 2021, adopted on December 28, 2020, these deadlines were extended by two full years. This allows for projects beginning during 2022 to access the 26% ITC if in service by January 1, 2026. Because of the extension of the ITC plus projections of future cost drops for solar and storage construction costs, these plans did not prove to be least cost at any of the prices modeled as can be seen in the results tables.

Resource Plan 1: In this resource plan a 553 MW (winter capacity) combined cycle gas-fired generator is added after the winter reserve margin drops below 21%. 523 MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 2: In this resource plan 523 MW (winter capacity) of ICTs are added when the winter reserve margin drops below 21% during the modeling period.

Resource Plan 3: In this resource plan Wateree units 1 and 2 are retired in 2028 and a combined cycle gas-fired generator is added in 2028. Five-hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 4: In this resource plan McMeekin 1 and 2 along with Urquhart 3 are retired in 2028. Their 346 MW of capacity are replaced by a 523 MW block of ICTs. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 5: In this resource plan 400 MW of Company-owned flexible solar generation plus 100 MW of battery storage are added in 2026. The next increment of capacity necessary to maintain a 21% winter reserve margin is a 553 MW combined cycle gas generator. After the CC, 523 MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 6: In this resource plan 400 MW of Company-owned flexible solar generation is added in 2026. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 7: In this resource plan 400 MW of flexible solar PPA generation plus 100 MW of battery storage are added in 2026. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 7a: In this resource plan 400 MW of flexible solar PPA at $38.94/MWh is added in 2023. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 7a2: In this resource plan 400 MW of flexible solar PPA at $36/MWh is added in 2023. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 7a3: In this resource plan 400 MW of flexible solar PPA at $34/MWh is added in 2023. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 7b: In this resource plan 400 MW of flexible solar PPA at $38.94/MWh plus 100 MW of battery storage PPA are added in 2023. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 7b2: In this resource plan 400 MW of flexible solar PPA at $36/MWh plus 100 MW of battery storage PPA are added in 2023. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 7b3: In this resource plan 400 MW of flexible solar PPA at $34/MWh plus 100 MW of battery storage PPA are added in 2023. Five hundred twenty-three MW blocks of ICTs are added to maintain the 21% winter reserve margin during the modeling period.

Resource Plan 8: In this resource plan Wateree and Williams are retired in 2028 and replaced with a 553 MW 1-on-1 combined cycle plant and 523 MW of ICTs. Dual fuel capability is eliminated at Cope, so Cope burns only natural gas starting in 2030. Additional tranches of 100 MW of battery storage and 131 MW ICTs are added to maintain the 21% winter reserve margin during the modeling period. Solar is added in 2026, 2027 and each year from 2029 to 2048. In this plan 1,900 to 2,000 MW of solar are added with 700 MW to 900 MW of storage.[7] This resource plan is the lowest carbon plan.

The timing and nature of resource additions and the resulting capacities and reserve margins for each of the 30 years of the model horizon are set forth in the tables attached as **Appendix G** to this document. Please note that winter and summer net dependable capacities are different for most resources and nameplate capacity and net dependable capacity will be different, particularly for solar capacity additions. The net capacity of each addition is reflected for summer and winter periods.

Methodology

The incremental revenue requirements associated with each of the fourteen resource plans was computed using the PROSYM computer program to estimate production costs and a Microsoft Office® EXCEL revenue requirements model to calculate the associated capital costs. The PROSYM model creates production costs values over a 30-year modeling period. The production costs values are added to the EXCEL file and the production costs are extrapolated for another 10 years to get 40 years of production costs values. Capital costs and DSM costs are calculated over 40 years. The EXCEL revenue requirements model combines the capital costs, DSM costs and production costs to estimate total incremental revenue requirements over a 40-year planning horizon. A levelized NPV is calculated for all costs over the 40-year period.

Demand Side Management Assumptions

Three DSM cases were created. The low DSM is equivalent to 90% of the 2019 Potential Study, which results in a reduction of 0.61% of retail sales. The medium DSM used the results of the initial rapid assessment of the 2019 Potential Study and results in a reduction of 0.73% of retail sales. High DSM assumed DSM growth to 1% of retail sales by 2022.

The three DSM cases created three demand and energy forecasts. A low level of DSM creates higher demands and energy. A high level of DSM creates demands and energies that are lower. The cost for each DSM case was calculated over a 40-year period and applied to the appropriate scenarios. Assuming no early retirements, the first need for additional capacity occurs in the winter of 2031 when using the Medium DSM demands, in 2030 when using the Low DSM demands and 2034 when using the High DSM demands.

The use of the Low, Medium and High DSM demands result in scenarios that measure the sensitivity of the resource plans to variations in future load growth. The Low, Medium and High economic load growth sensitivities are also a measure of potential variation in future load growth and are largely duplicative of the DSM sensitivities. The economic load growth sensitivities were not modeled in order to hold the number of scenarios modeled to a manageable group. If all six economic load growth sensitivity combinations were modeled (i.e., low, medium, high load growth, as well as two electric vehicle sensitives), the number of scenarios presented would be 2,268 scenarios, which is not practical. The three DSM cases provide a range of load growth assumptions that show the sensitivity of the resource plans to load growth variations and meet the requirements of Act No. 62.

Emissions, DSM and Fuel Sensitivity

The three DSM cases were evaluated using three gas price assumption plus three CO_2 cost assumptions. The combination of the three DSM assumptions, three gas price assumptions and three CO_2 cost assumptions created 27 different sensitivities. All plans include assumptions about

[7] The amount of solar generation added depends on the DSM assumption being modeled. Low DSM results in faster load growth with results in more generation assets being added.

expenses that will be required to meet Effluent Limitation Guidelines for Wateree and Williams if those units are assumed to operate after 2028. The fourteen resource plans times the 27 sensitivities equal 378 different scenarios.

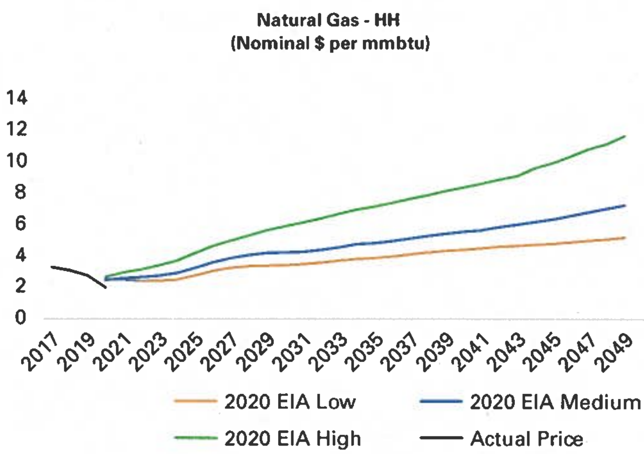
The chart to the right shows the three gas price forecasts used that, consistent with Order No. 2020-832, are based on the 2020 EIA Annual Energy Outlook that was published in March of 2020. The high gas price forecast assumes that national gas markets experience a significant reduction in available gas supplies going forward, while the low gas price forecast assumes an increase in available gas during the forecast period. It should be noted that all three forecasts start at levels that are markedly above actual natural gas prices for 2020 and have already displayed a high bias.

Three CO_2 price assumptions were modeled. Zero dollars/ton is the low CO_2 assumption. This is consistent with current prices and provides a no-action base line to measure the sensitivity of generation plans to CO_2 emissions regulations.

The medium CO_2 price case assumes a price of $12/short ton beginning in 2030 and is based on the CO_2 price forecast provided by IHS Markit in November 2020. IHS is a leading forecasting and consulting firm with a global reputation for reasonable forecasts. The assumptions behind the $12 CO_2 forecast are as follows: *"Compelled by the courts and the [prior regulatory findings that CO_2 emissions constitute health and environmental endangerment], the EPA implements the Affordable Clean Energy rule, a modest and narrowly focused power sector CO_2 regulation under the Clean Air Act (CAA). The US plan to withdraw from the Paris Agreement in 2020 stalls in the face of growing political backlash, and is reversed in 2021. The combination of broad domestic and international pressure for further action (beyond CAA regulations), return to the Paris Agreement, and US business desire for greater long-term policy certainty than CAA regulations provide, prompt legislative action in the early 2020s to establish a CO_2 price for the power sector outside California (which continues its own economy wide program). Political negotiations yield a modest CO_2 price that begins in 2030 and escalates annually."* The $12/short ton in nominal dollars begins in 2030 and grows at 10%/year.

The high CO_2 price scenario is $35/metric ton beginning in 2021 and grows at 7.5%/year. This case was specified as a case to be modeled in Order No. 2020-832. However, there are substantial reasons to question its validity for use as a forecasted sensitivity. The basis for the $35/ton high CO_2 case is the EIA reference document "AEO 2020 Alternative Policies, Carbon Fees, March 2020." Unlike the IHS Markit CO_2 price data, the reference document does not provide a forecast of potential CO_2 costs, but uses somewhat randomly selected CO_2 cost values ($15/ton, $25/ton and $35/ton) as sensitivities chosen to stress the EIA model's forecasts of future energy markets. The EIA makes no claims that the sensitivities it modeled reflect reasonable forecasts of future CO_2 costs and made no attempt to justify the reasonableness of any of these levels of CO_2 cost. As EIA says, *"the assumptions used in the alternative cases should not be construed as EIA opinion regarding how laws or regulations should, or are likely to, be changed." (p. 3) Further comments by EIA state, "[I]n the area of policies that target emissions reduction, history has demonstrated that there is significant uncertainty in this assumption." (p.16)*

Low, Base and High Gas Price Forecast



The $35/ton and 7.5% escalation case does not in DESC's opinion represent a likely or possible CO_2 price forecast. Escalation at 7.5% results in a CO_2 price of $255 per metric ton by 2049. Under the $35/ton scenario, costs to DESC customers could increase by approximately $2 billion per year by 2049. This level of customer impact is indicative of impacts that would be experienced throughout the economy from CO_2 prices at this level; therefore, imposing CO_2 prices of this magnitude are not in DESC's opinion reasonably foreseeable.

Results

This section of the Modified 2020 IRP shows the result of using eight metrics for the comparative evaluation of the fourteen resource plans. Those eight metrics are:

- Levelized Cost
- CO_2 Emissions
- Clean Energy
- Fuel Cost Resiliency
- Generation Diversity
- Reliability Factors
- Mini-Max Regret Analysis
- Cost Range Analysis

The evaluation of the fourteen resource plans across these eight metrics provides a systematic and quantitative assessment of the factors relevant to the selection of a preferred resource plan. But as discussed below, the value of that assessment depends on the quality of the assumptions on which the resource plans have been based or on which they have modeled and the likelihood that those specific sensitivity cases or something close to them will occur. Applying these metrics to a set of scenarios that includes scenarios with highly unlikely cost forecasts or sensitivities will produce distorted rankings and can lead to misleading conclusions. As noted below, certain of the cost forecasts or sensitivities that DESC has been required to model involve forecasts that are not supported (i.e., \$35/ton CO_2 costs imposed in 2021 and escalating at 7.5% from that point forward) or cost forecasts for renewable energy projects that are excessively low and do not lead to meaningful results.

Utility Partners of America, contractor for Dominion Energy, installing new smart meters for customers.

Resource Plan Analysis

The resource plans are modeled against 27 sensitivities. They include three sensitivities each for DSM, CO_2 Cost and Gas Price.

These plans are evaluated against eight metrics. Three of the eight metrics (Clean Energy, Generation Diversity, and Reliability Factors) vary according to the resource plan being evaluated, but do not materially change with the DSM level, CO_2 Cost or Gas Price sensitivity being modeled. For that reason, only a single evaluation table is provided for each of these three metrics.

Two of the metrics, Mini-Max Regret Analysis and Cost Range Analysis, measure variation in the modeling results across all 27 sensitivities. By their nature, only a single ranking of the results across all sensitivities is produced.

In ranking the resource plans, ties were assigned the average score within the tie. Rankings among scenarios were compared, and those rankings were averaged to present a singular ranking for each of the fourteen resource plans under each metric. These results are presented in the table: Resource Plan Rankings Over All Scenarios. It should be noted that in accordance with Order No. 2020-832, this evaluation weighs highly unlikely forecast scenarios and highly likely scenarios equally, making the results potentially misleading where they represent rankings averaged against all 27 sensitivities.

The fourteen resource plans are also evaluated against the most reasonable and likely set of sensitivities. The results of that ranking are presented at the conclusion of the analysis. The most reasonable and likely sensitivities constitute the Expected Case in DESC's judgement. They are the level of demand reduction produced by the High DSM case; the $12/ton CO_2 Price sensitivity, and the Low Gas Price forecast. In DESC's judgement, this set of sensitivities presents the most likely future conditions under which the plans will have to function.

As discussed below, the same resource plan, RP8, consistently emerges as the most reasonable resource plan across the largest number of scenarios. This is true regardless of whether the evaluation is conducted against all 27 sensitivities or the Expected Case.

The following table maps each of the eight metrics with the IRP Statute or a directive in Order No. 2020-832, or both:

IRP Evaluation Standards and Metrics

Levelized Cost
Section 58-37-40(C)(2)(b) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of consumer affordability and least cost. Order No. 2020-832 also required the costs of all candidate resource plans be included.

CO_2 Emissions
Section 58-37-40(C)(2)(c) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of compliance with applicable state and federal environmental regulations.

Clean Energy
Section 58-37-40(C)(2)(c) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of compliance with applicable state and federal environmental regulations.

Fuel Cost Resiliency
Section 58-37-40(C)(2)(e) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of commodity price risks, which includes fuel cost resiliency.

Generation Diversity
Section 58-37-40(C)(2)(f) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of diversity of generation supply.

Reliability Factors
Section 58-37-40(C)(2)(d) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of power supply reliability.

Mini-Max Regret
Order No. 2020-832 required DESC to implement a Mini-Max regret analyses in the Modified 2020 IRP.

Cost Range Analysis
Section 58-37-40(C)(2)(b) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of consumer affordability and least cost. Order No. 2020-832 also required DESC to implement a Cost Range analysis in the Modified 2020 IRP.

Levelized Cost

The Levelized Cost metric is a comprehensive measure of the relative costs to customers of each of the fourteen resource plans over the 40-year period from 2020-2059. The comparison is based on the forty year levelized net present value of the incremental costs of each resource plan. The incremental costs include incremental operating costs, capital costs for new generation, incremental capital costs for ongoing operation and maintenance, and DSM costs.

The following tables summarize rankings of all fourteen resource plans under the three different DSM scenarios, three different gas price cases and three different CO_2 price cases. The results are color coded: 1 - Green= Least cost, 2 – Blue = Second Lowest and 8 - Orange = Highest cost. Each of the three tables shows the rankings of the plans under one of the three DSM scenarios and provides the rankings under that DSM scenario for three CO_2 price scenarios and three Gas Price scenarios. Between the three tables, the rankings for all fourteen resource plans are provided for all 27 CO_2, Natural Gas and DSM scenarios.

Levelized NPV Cost Results for the High DSM Scenario

RP ID	Resource Plan Name	$0/ton CO_2			$12/ton CO_2			$35/ton CO_2		
		Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
RP1	CC	9	9	10	8	11	9	11	11	11
RP2	ICT	7	8	9	12	12	10	13	13	13
RP3	Retire Wateree	5	10	13	3	6	12	2	2	3
RP4	Retire McMeekin	14	13	12	14	14	13	14	14	14
RP5	Solar + Storage	11	11	8	11	10	8	5	3	2
RP6	Solar	12	12	11	13	13	11	12	12	12
RP7	Solar PPA + Storage 2026	1	1	1	2	2	1	6	7	6
RP7a	Solar PPA 2023	10	7	7	10	9	7	10	8	10
RP7a2	Solar PPA 2023	8	6	6	9	8	6	9	8	9
RP7a3	Solar PPA 2023	6	5	5	7	7	5	8	8	8
RP7b	Solar PPA + Storage 2023	4	4	4	6	5	4	7	4	7
RP7b2	Solar PPA + Storage 2023	3	3	3	5	4	3	4	4	5
RP7b3	Solar PPA + Storage 2023	2	2	2	4	3	2	3	4	4
RP8	Retire Coal	13	14	14	1	1	14	1	1	1

Levelized NPV Cost Results for the Medium DSM Scenario										
RP ID	Resource Plan Name	$0/ton CO_2			$12/ton CO_2			$35/ton CO_2		
		Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
RP1	CC	6	8	10	8	8	10	9	9	11
RP2	ICT	8	10	9	12	12	11	13	13	13
RP3	Retire Wateree	5	11	13	6	7	13	2	2	3
RP4	Retire McMeekin	13	12	12	14	14	14	14	14	14
RP5	Solar + Storage	9	6	8	7	6	6	3	3	2
RP6	Solar	14	13	11	13	13	12	12	12	12
RP7	Solar PPA + Storage 2026	1	1	1	2	2	1	5	5	6
RP7a	Solar PPA 2023	11	9	7	11	11	9	11	11	10
RP7a2	Solar PPA 2023	10	7	6	10	10	8	10	10	9
RP7a3	Solar PPA 2023	7	5	5	9	9	7	8	8	8
RP7b	Solar PPA + Storage 2023	4	4	4	5	5	5	7	7	7
RP7b2	Solar PPA + Storage 2023	3	3	3	4	4	3	6	6	5
RP7b3	Solar PPA + Storage 2023	2	2	2	3	3	2	4	4	4
RP8	Replace Coal	12	14	14	1	1	4	1	1	1

Dominion Energy

Our Company

Resource Plan Analysis

Levelized NPV Cost Results for the Low DSM Scenario

RP ID	Resource Plan Name	$0/ton CO_2			$12/ton CO_2			$35/ton CO_2		
		Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
RP1	CC	6	8	9	7	7	8	7	7	10
RP2	ICT	9	10	8	11	11	11	13	13	13
RP3	Retire Wateree	3	5	12	3	3	9	2	2	2
RP4	Retire McMeekin	11	12	11	13	13	12	14	14	14
RP5	Solar + Storage	14	14	13	14	14	14	12	12	12
RP6	Solar	13	11	10	12	12	10	11	11	11
RP7	Solar PPA + Storage 2026	1	1	1	2	2	1	3	4	5
RP7a	Solar PPA 2023	10	9	7	10	10	7	10	10	9
RP7a2	Solar PPA 2023	8	7	6	9	9	6	9	9	8
RP7a3	Solar PPA 2023	7	6	5	8	8	5	8	8	7
RP7b	Solar PPA + Storage 2023	5	4	4	6	6	4	6	6	6
RP7b2	Solar PPA + Storage 2023	4	3	3	5	5	3	5	5	4
RP7b3	Solar PPA + Storage 2023	2	2	2	4	4	2	4	3	3
RP8	Replace Coal	12	13	14	1	1	13	1	1	1

Using this measure, RP8 is the least cost resource plan in the majority of scenarios. RP7 is the least cost plan in those scenarios where RP8 is not.

The table that follows provides the data on which rankings were made, specifically levelized costs in millions of dollars for each of the fourteen resource plans. In the interest of brevity, only the results for nine scenarios under the High DSM sensitivity, are presented. DESC has committed to pursue the high DSM path. Similar charts for the Low and Medium DSM scenarios are attached at **Appendix H.**

Levelized Costs in the High DSM Scenario ($M)

RP ID	Resource Plan Name	$0/ton CO_2			$12/ton CO_2			$35/ton CO_2		
($M)		Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
RP1	CC	1,517	1,590	1,719	1,684	1,762	1,909	2,424	2,511	2,696
RP2	ICT	1,516	1,588	1,717	1,690	1,768	1,914	2,449	2,539	2,724
RP3	Retire Wateree	1,515	1,593	1,749	1,673	1,756	1,922	2,382	2,472	2,667
RP4	Retire McMeekin	1,537	1,609	1,736	1,711	1,789	1,933	2,470	2,558	2,742
RP5	Solar + Storage	1,526	1,595	1,716	1,687	1,762	1,902	2,406	2,490	2,667
RP6	Solar	1,531	1,601	1,724	1,699	1,774	1,915	2,434	2,521	2,701
RP7	Solar PPA + Storage 2026	1,506	1,576	1,697	1,673	1,749	1,888	2,406	2,494	2,673
RP7a	Solar PPA 2023	1,519	1,588	1,710	1,686	1,761	1,901	2,418	2,502	2,683
RP7a2	Solar PPA 2023	1,517	1,586	1,708	1,684	1,759	1,899	2,416	2,502	2,682
RP7a3	Solar PPA 2023	1,515	1,585	1,707	1,683	1,758	1,898	2,415	2,502	2,680
RP7b	Solar PPA + Storage 2023	1,512	1,582	1,701	1,679	1,754	1,893	2,408	2,492	2,674
RP7b2	Solar PPA + Storage 2023	1,510	1,580	1,700	1,677	1,753	1,891	2,406	2,492	2,672
RP7b3	Solar PPA + Storage 2023	1,509	1,579	1,698	1,676	1,751	1,889	2,404	2,492	2,671
RP8	Retire Coal	1,536	1,626	1,823	1,653	1,743	1,940	2,239	2,332	2,543

Dominion Energy

2049 CO_2 Emissions

The fourteen resource plans are structured to comply with current environmental regulations on the operations of electric generating stations, which are among the most stringent that apply to any industry in the United States. Going forward, the single most important environmental challenge for electric generation will be limiting carbon emissions. This is a particularly important consideration for DESC's customers and for DESC in light of the recently announced net-zero carbon commitment that Dominion Energy has adopted. The following tables summarize the performance of all fourteen resource plans in regards to the CO_2 Emissions as forecasted at the end of 40-year period ending in 2049. The tables below rank the fourteen resource plans under each of the 27 scenarios that have been modeled. For CO_2, the scale is 1 – Lowest, 2 – Second Lowest and 14 – Highest emissions. Note that in some cases, plans have identical or nearly identical emissions and so are tied.

CO_2 Emissions Rankings in the High DSM Scenario

CO_2 Ranking	High DSM					
	$12/ton CO_2			$35/ton CO_2		
	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
	2049	2049	2049	2049	2049	2049
RP1	4	4	4	4	4	4
RP2	13	13	13	13	13	13
RP3	4	4	4	4	4	4
RP4	14	14	14	14	14	14
RP5	2	2	2	2	2	2
RP6	5	8	8	9	5	8
RP7	12	12	12	5	11	11
RP7a	7	6	6	11	7	6
RP7a2	7	6	6	11	7	6
RP7a3	7	6	6	11	7	6
RP7b	10	10	10	7	11	11
RP7b2	10	10	10	7	11	11
RP7b3	10	10	10	7	11	11
RP8	1	1	1	1	1	1

Dominion Energy

Our Company

Resource Plan Analysis

CO_2 Emissions Rankings in the Medium DSM Scenario						
CO_2 Ranking	Medium DSM					
	\$12/ton CO_2			\$35/ton CO_2		
	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
	2049	2049	2049	2049	2049	2049
RP1	4	4	4	4	4	4
RP2	14	14	14	14	13	13
RP3	4	4	4	4	4	4
RP4	13	13	13	13	14	14
RP5	2	2	2	2	2	2
RP6	12	12	9	12	9	9
RP7	5	8	5	7	7	7
RP7a	10	10	11	10	11	11
RP7a2	10	10	11	10	11	11
RP7a3	10	10	11	10	11	11
RP7b	7	6	7	7	7	7
RP7b2	7	6	7	7	7	7
RP7b3	7	6	7	7	7	7
RP8	1	1	1	1	1	1

Dominion Energy

Resource Plan Analysis

CO_2 Emissions Rankings in the Low DSM Scenario						
CO_2 Ranking	Low DSM					
	\$12/ton CO_2			\$35/ton CO_2		
	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
	2049	2049	2049	2049	2049	2049
RP1	4	3	3	4	4	3
RP2	14	14	14	13	13	13
RP3	3	4	4	4	4	13
RP4	13	13	13	14	14	14
RP5	2	2	2	2	2	2
RP6	9	9	6	9	9	7
RP7	5	5	5	5	5	11
RP7a	7	11	8	11	7	9
RP7a2	7	11	8	11	7	9
RP7a3	7	11	8	11	7	9
RP7b	11	7	11	7	11	5
RP7b2	11	7	11	7	11	5
RP7b3	11	7	11	7	11	5
RP8	1	1	1	1	1	1

The resource plan with the consistently highest impact in reducing CO_2 emissions is RP8. This results from retiring two large coal stations in 2028 and converting the third and last such station to gas-fired only status in 2030. In addition, RP8 envisions the addition of between 1,900 and 2,000 MW of new solar capacity and between 700 and 900 MW of battery storage. The resource plan with the second highest reduction in CO_2 emissions is RP3. This plan envisions the early retirement of only one coal plant, Wateree Station.

The next table shows the specific tons of CO_2 emitted by power generation on DESC's system in 2049. The chart shows the performance of the fourteen resource plans in tons of CO_2 against six combinations of sensitivities for CO_2 costs and for Gas Prices. However, in the interest of brevity, only the results under the High DSM scenario are presented. Similar charts for the Low and Medium DSM scenarios are attached at **Appendix I.**

The CO_2 emissions for the plans other than RP8 are tightly grouped together. Among all plans other than RP8, there is little CO_2 reduction in the early years. As the CO_2 price grows, a small reduction in total CO_2 occurs under these plans by 2049.

CO_2 Emissions in the High DSM Scenario (000 tons)

CO_2 (000 tons)	High DSM					
	$12/ton CO_2			$35/ton CO_2		
	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
	2049	2049	2049	2049	2049	2049
RP1	11,059	11,243	11,875	10,634	10,741	11,008
RP2	11,750	11,989	12,492	11,333	11,456	11,660
RP3	11,059	11,243	11,875	10,634	10,741	11,008
RP4	12,004	12,186	12,668	11,456	11,550	11,784
RP5	10,652	10,906	11,500	10,214	10,297	10,546
RP6	11,371	11,541	12,081	10,928	11,017	11,284
RP7	11,430	11,643	12,133	10,918	11,046	11,303
RP7a	11,371	11,537	12,081	10,932	11,017	11,284
RP7a2	11,371	11,537	12,081	10,932	11,017	11,284
RP7a3	11,371	11,537	12,081	10,932	11,017	11,284
RP7b	11,429	11,643	12,132	10,918	11,046	11,303
RP7b2	11,429	11,643	12,132	10,918	11,046	11,303
RP7b3	11,429	11,643	12,132	10,918	11,046	11,303
RP8	8,589	8,565	8,611	8,165	8,204	8,340

Dominion Energy

Our Company

Resource Plan Analysis

The modeling also showed that neither changes in the assumed CO_2 price nor in the assumed gas price had a significant impact on the CO_2 level emitted. The \$35/ton CO_2 case grows to \$255/short ton by 2049 whereas the \$12/ton CO_2 case only grows to \$73/short ton by 2049. The 250% increase in CO_2 price in 2049 under the \$35/ton sensitivity only results in a 4% to 5% reduction in CO_2 emissions when low or medium gas prices are assumed. However, under that \$35/ton sensitivity, DESC's customers would pay approximately \$2 billion per year in carbon cost payments for that 4% to 5% CO_2 reduction.

Clean Energy

The Clean Energy metric compares the fourteen resources plans based on how much energy they produced with non-emitting generation to meet customers' energy needs over each five-year period during the forty-year planning horizon, 2020-2049. Clean Energy includes energy generated by nuclear, solar and hydro facilities. The modeling shows that all resource plans include between 26% and 39% Clean Energy at the end of the forecast period. But while the amount of clean energy varies by resource plan, it does not vary significantly by DSM, CO_2 or Gas Price sensitivity modeled. This is because the models assume economic dispatch, and under economic dispatch, the system will use as much solar, nuclear and hydro energy to meet customers' needs as is possible. The values in the table show the total Clean Energy by resource plan by five-year period for the High DSM, Low Gas, and \$12/ton CO_2 scenarios only. Once again, the results for the RP7a1-3 and RP7b1-3 were identical and so are presented collectively as RP7a and RP7b.

Using the 2049 Clean Energy metric, RP8 performed best in three of the six five-year periods assessed. RP7b ranked best in the two remaining periods. At the end of the period, RP8 resulted in 32% more Clean Energy than the next highest scoring plan, which was RP7b.

Clean Energy by Resource Plan – High DSM (GWh)							
Resource Plan ID	Resource Plan Name	2020-2024	2025-2029	2030-2034	R2035-2039	2040-2044	2045-2049
RP1	CC	29,520	38,399	37,943	38,380	38,380	37,962
RP2	ICT	29,520	38,399	37,943	38,380	38,380	37,962
RP3	Retire Wateree	29,520	38,399	37,943	38,380	38,380	37,962
RP4	Retire McMeekin	29,520	38,399	37,943	38,380	38,380	37,963
RP5	Solar + Storage	29,520	40,615	41,748	42,278	42,389	42,081
RP6	Solar	29,520	40,617	41,740	42,272	42,395	42,081
RP7	Solar PPA + Storage	29,520	40,615	41,748	42,280	42,398	42,090
RP7a	Solar PPA + Storage	30,278	42,098	41,737	42,267	42,398	42,083
RP7b	Solar PPA + Storage	30,287	42,107	41,744	42,289	42,393	42,086
RP8	Retire Coal	29,520	38,877	40,995	46,374	51,317	55,623

Fuel Cost Analysis

An appropriate consideration in evaluating generation plans is their resiliency in the face of fuel cost risks. The Levelized Cost of generation plans as modeled in this Modified 2020 IRP fully captures fuel costs and anticipated changes in fuel costs over a 40-year planning horizon for each plan. As a result, the Levelized Cost metric provides important data about how plans perform in the face of fuel price changes. In addition, three sets of natural gas price forecasts have been modeled as part of the 27 sensitivities. These natural gas price sensitivities further capture the resiliency of the generation plans in the face of fuel price risk.

Measuring fuel price sensitivities through the use of natural gas price sensitivities is logical and appropriate under current conditions. Coal is declining rapidly as a generation fuel. Nuclear fuel is a small component of the cost of nuclear generation. The use of fuel oil on DESC's system is minimal. As a result, until new fuels like hydrogen mature as fuels for electricity generation, natural gas will be the predominate fuel going forward.

In the interest of providing an additional systematic and quantitative assessment of fuel price risk, the following table focuses on fuel costs only as a component of cost under the fourteen resource plans. The fuel cost incurred under each of the fourteen plans was calculated under each of the 27 sensitivities modeled, and the plans were then ranked as shown below:

Fuel Costs Rankings in the High DSM Scenario

		High DSM								
RP ID	Resource Plan Name	$0/ton CO_2			$12/ton CO_2			$35/ton CO_2		
		Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
RP1	CC	3	2	10	3	2	10	3	3	5
RP2	ICT	13	13	11	13	13	11	13	13	13
RP3	Retire Wateree	4	12	12	4	12	12	4	7	11
RP4	Retire McMeekin	14	14	13	14	14	13	14	14	14
RP5	Solar + Storage	1	1	1	1	1	1	1	1	1
RP6	Solar	11	10	8	11	10	8	11	11	10
RP7	Solar PPA + Storage 2026	12	11	9	12	11	9	12	12	9
RP7a	Solar PPA 2023	6	5	6	6	5	6	9	9	7
RP7a2	Solar PPA 2023	6	5	6	6	5	6	9	9	7
RP7a3	Solar PPA 2023	6	5	6	6	5	6	9	9	7
RP7b	Solar PPA + Storage 2023	9	8	3	9	8	3	6	5	3
RP7b2	Solar PPA + Storage 2023	9	8	3	9	8	3	6	5	3
RP7b3	Solar PPA + Storage 2023	9	8	3	9	8	3	6	5	3
RP8	Retire Coal	2	3	14	2	3	14	2	2	12

Fuel Costs Rankings in the Medium DSM Scenario

		Medium DSM								
RP ID	Resource Plan Name	$0/ton CO_2			$12/ton CO_2			$35/ton CO_2		
		Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
RP1	CC	6	7	9	6	7	9	3	3	6
RP2	ICT	13	13	11	13	13	11	13	13	13
RP3	Retire Wateree	8	12	12	8	12	12	7	8	11
RP4	Retire McMeekin	14	14	13	14	14	13	14	14	14
RP5	Solar + Storage	2	1	1	2	1	1	1	1	1
RP6	Solar	12	11	10	12	11	10	12	12	10
RP7	Solar PPA + Storage 2026	7	6	5	7	6	5	8	7	5
RP7a	Solar PPA 2023	10	9	7	10	9	7	10	10	8
RP7a2	Solar PPA 2023	10	9	7	10	9	7	10	10	8
RP7a3	Solar PPA 2023	10	9	7	10	9	7	10	10	8
RP7b	Solar PPA + Storage 2023	4	4	3	4	4	3	5	5	3
RP7b2	Solar PPA + Storage 2023	4	4	3	4	4	3	5	5	3
RP7b3	Solar PPA + Storage 2023	4	4	3	4	4	3	5	5	3
RP8	Retire Coal	1	2	14	1	2	14	2	2	12

Fuel Costs Rankings in the Low DSM Scenario

		Low DSM								
RP ID	Resource Plan Name	$0/ton CO_2			$12/ton CO_2			$35/ton CO_2		
		Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
RP1	CC	2	3	8	2	3	14	2	2	1
RP2	ICT	13	13	12	13	13	10	13	13	13
RP3	Retire Wateree	3	7	11	3	7	11	3	7	11
RP4	Retire McMeekin	14	14	13	14	14	12	14	14	14
RP5	Solar + Storage	12	12	10	12	12	1	12	12	10
RP6	Solar	11	11	9	11	11	9	11	11	9
RP7	Solar PPA + Storage 2026	4	2	4	4	2	8	7	6	5
RP7a	Solar PPA 2023	9	9	6	9	9	6	9	9	7
RP7a2	Solar PPA 2023	9	9	6	9	9	6	9	9	7
RP7a3	Solar PPA 2023	9	9	6	9	9	6	9	9	7
RP7b	Solar PPA + Storage 2023	6	5	2	6	5	3	5	4	3
RP7b2	Solar PPA + Storage 2023	6	5	2	6	5	3	5	4	3
RP7b3	Solar PPA + Storage 2023	6	5	2	6	5	3	5	4	3
RP8	Retire Coal	1	1	14	1	1	13	1	1	12

In the majority of scenarios, RP5 and RP8 produce the lowest total fuel costs. These two resource plans add combined cycle gas generation with the additional fixed gas transportation costs associated with them. Despite this, they have the lowest total fuel costs in most of the scenarios due to the highly fuel-efficient nature of combined cycle generation. RP4, which retires McMeekin 1 and 2 and Urquhart 3 and meets the reserve margin requirements with the addition of ICTs, consistently shows the highest fuel cost. But this analysis of fuel cost resiliency under multiple sensitivities shows that RP5 and RP8 have superior performance in terms of fuel cost resiliency.

The next table shows the actual fuel costs in millions of dollars for each of the fourteen resource plans as evaluated against nine combinations of sensitivities for CO_2 costs and for Gas Prices. In the interest of brevity, only the results under the High DSM scenario are presented. Charts for the Low and Medium DSM scenarios are attached at **Appendix J**. The results for the other eighteen scenarios are similar.

Dominion Energy

Our Company

Resource Plan Analysis

Fuel Costs in the High DSM Scenario ($M)										
		High DSM								
RP ID	Resource Plan Name	$0/ton CO_2			$12/ton CO_2			$35/ton CO_2		
		Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
RP1	CC	822	897	1,031	822	897	1,031	850	931	1,094
RP2	ICT	848	923	1,056	848	923	1,056	879	963	1,128
RP3	Retire Wateree	826	906	1,062	826	906	1,062	851	936	1,110
RP4	Retire McMeekin	867	942	1,072	867	942	1,072	896	978	1,142
RP5	Solar + Storage	806	878	1,004	806	878	1,004	832	909	1,064
RP6	Solar	830	902	1,029	830	902	1,029	858	939	1,098
RP7	Solar PPA + Storage 2026	833	905	1,030	833	905	1,030	859	939	1,097
RP7a	Solar PPA 2023	829	900	1,026	829	900	1,026	856	936	1,094
RP7a2	Solar PPA 2023	829	900	1,026	829	900	1,026	856	936	1,094
RP7a3	Solar PPA 2023	829	900	1,026	829	900	1,026	856	936	1,094
RP7b	Solar PPA + Storage 2023	830	902	1,026	830	902	1,026	855	935	1,093
RP7b2	Solar PPA + Storage 2023	830	902	1,026	830	902	1,026	855	935	1,093
RP7b3	Solar PPA + Storage 2023	830	902	1,026	830	902	1,026	855	935	1,093
RP8	Retire Coal	810	900	1,098	810	900	1,098	834	924	1,123

Generation Diversity

Apart from RP7a1-3 and RP7b1-3 (which model identical resource plans with alternative solar PPA price assumptions), each of the resource plans modeled here assumes the addition or retirement of different suites of generation sources. For that reason, each of the plans results in a different level of generation diversity at the close of the planning period.

Generation Diversity for High DSM, Low Gas, \$12/ton CO_2

Resource Plan	Name	Diversity Score	Rank
RP1	Combined Cycle	0.262	3
RP2	ICT	0.329	13
RP3	Retire Wateree	0.262	3
RP4	Retire McMeekin	0.386	14
RP5	Solar + Storage	0.247	2
RP6	Solar	0.313	10
RP7	Solar PPA + Storage 2026	0.309	6
RP7a	Solar PPA 2023	0.313	10
RP7a2	Solar PPA 2023	0.313	10
RP7a3	Solar PPA 2023	0.313	10
RP7b	Solar PPA + Storage 2023	0.309	6
RP7b2	Solar PPA + Storage 2023	0.309	6
RP7b3	Solar PPA + Storage 2023	0.309	6
RP8	Retire Coal	0.206	1

To provide a systematic and quantitative assessment of generation diversity, the chart that follows ranks the generation diversity of each resource plan according to the percentage that the generation mix it creates is concentrated in any one type of generation asset. Under this analysis, a plan that leads to a generation system with a single type of generation asset representing 35% of its generation mix would have less generation diversity than a plan where no generation resource type represented more than 25% of its generation mix.

Ranking the resource plans based on this metric shows that across all plans, the level of concentration in a single type of generation resource varies between a high of 39% for RP4 to a low of 21% for RP8. In RP4, the generation type representing the greatest source of concentration was large-frame internal combustion turbines. In RP8, the generation type representing the greatest source of concentration was solar. RP8 is the plan that scores best on this metric by a significant margin. The MWs of each generation type for each resource plan by year is provided in **Appendix K**. This exhibit provides the data used for the ranking.

While this is a valid approach to measuring diversity, DESC will continue to evaluate other potential approaches and engage with the IRP Stakeholders Advisory Group to ensure that future IRPs and IRP updates continue to appropriately capture this factor.

Reliability Analysis

DESC's resource plans incorporate system reliability considerations into its methodology at the foundational level. All fourteen resource plans have been formulated to meet a common reliability standard and so ensure that the resources included in each resource plan collectively meet a system reliability goal by providing a seasonal peak hour reserve margin that is common to all plans. In creating resource plans capable of meeting that common goal, the particular operating characteristic and reliability contributions of each generation resource is considered. All plans are designed with reliability as a priority. No plans are formulated to provide greater or less resources than are necessary to meet the reliability criteria.

To provide a more systematic and more comprehensive assessment of reliability as required by the IRP Statute and Order No. 2020-832, DESC has also devised a means of scoring the reliability contribution of the specific generation resources included in each resource plan. DESC

Dominion Energy

Our Company

Resource Plan Analysis

Reliability Factor	Able to generate or become a load, shift energy, and complement renewables.
Energy Storage	The units have the ability to shift supplies of energy between high and low load periods which aids reliability.
Limited Energy Source	The unit is able to function as a source of energy whose output normalizes to 16 hours/day of full load production but has limited abilities to replace 24-hour resources.
Dispatchability	The unit will respond to directives from system operators regarding its status, output, and timing. The Dispatchability of intermittent resources is limited and so their score is subject to a deduction. They cannot be counted as firm and require additional reserves.
Operational Flexibility	The unit is able to cycle and ramp up and down with little or no adverse impact on fuel costs or physical damage to the unit. Deductions are made if the units have a minimum operating load below which it cannot be dispatched.
Coincident Peak Output	The unit has the ability to provide energy and capacity to meet customer requirements during the winter peak demand period.
AGC	The unit has the ability to be placed on Automatic Generation Control allowing its output to be ramped up or down automatically to respond immediately to changes on the system.
Fast Start	The unit can respond from an offline condition and serve load in less than 10 minutes.
Inertia (non-inverter)	The unit operates using large rotating machinery (turbines, shafts, stators, exciters, etc.) that provide an inertial energy reservoir or a sink to stabilize the system. The rotation of this mass of machinery (inertia) provides frequency support.
VAR support	The unit can be used to send VARs out onto the system or consume excess VARs and so can be used to control voltage
Geographic Diversity	The unit can be located in diverse locations and is not restricted by fuel infrastructure.
Proximity to Load	The unit has a compact footprint and low impact outside of the fence. It can often be sited near load centers.
Synchronous Condensing	The unit can provide voltage support (VARS) even when not producing energy (synchronous condensing).
Black Start	The unit can be used in the first step to system restoration after an outage.

has identified a set of reliability factors that measure the generation types' ability to supply certain ancillary services, operating characteristics, and capabilities and meet certain locational considerations that support grid requirements in normal operations and in restoring power after storms or outages.

Some resources like energy storage are specifically designed to provide both reliability and economic benefits to the system. They have the ability to store energy and then return it to the system in response to operational directives. This ***Energy Storage*** function is a reliability benefit that batteries, pumped storage, and a few other technologies can provide.

On the other hand, batteries and pumped storage are a ***Limited Energy Source.*** Their ability to respond to system need becomes exhausted as their supply of energy is expended. For that reason, their reliability factor is reduced as compared to a resource that can operate as a 16-hour per day (on-peak) resource.

Reliability benefits are programmed into the controls of most conventional generators. They can respond affirmatively to operational directives to increase or decrease their output, or to come on line or go off line. This feature is important to maintaining the reliability of the system. For that reason, these resources are credited with ***Dispatchability.***

Operational Flexibility describes the ability of a generation resource to change output and state of operation easily, frequently and without large cost impacts and many times a day or night. Large steam units score poorly on the Operational Flexibility metric due to slow start up and rigid minimum up and down times. Due to design, aeroderivative ICTs and batteries score well as they do not have those restrictions. Thermal generation normally has an operating restriction at low load called minimum load that impacts the operation of the grid and other generators in low load conditions. Large steam units receive a deduction for this lack of flexibility. Batteries are credited for lack of a minimum load restriction and for their ability to absorb unneeded energy while charging.

Coincident Peak Output credits resources that can be counted as firm during the system's 15-minute peak demand period. Resources are scored on their ability to contribute to meeting that need reliably. DESC customers place the highest demands on the system in the winter at or just before sunrise when PV solar is not generating. Solar does not benefit from this reliability credit.

Resources that can respond to ***Automatic Generation Control*** signals will automatically adjust their output, up or down, based on system conditions at any time, day or night. They do so immediately without waiting for operator intervention. Such units are assigned a positive reliability value. Experience on the DESC system has shown that combined-cycle generators make the strongest contribution to reliability in this category.

Units that can go from an offline condition to serving their rated load within 10-minutes are ***Fast Start*** units. They can be of critical importance to reliability in responding to emergency events on the system. Aeroderivative ICTs and batteries score well in this measure.

Inertia is highly valued on electric grids because it provides the energy reservoir or energy sink needed to respond instantaneously to dips or spikes in frequency on the system caused by sudden changes in the relationship between load and generation. Inertia is provided by rapidly spinning turbines, shafts, stators, exciters and other rotating machinery in thermal generations equipment. Inertial energy keeps the system's ability to remain within acceptable frequency limits after an unexpected event until other generation can be ramped up to restore the balance of energy to load. In the same way, if frequency begins to spike, the excess energy on the system is converted into additional inertial energy by this spinning equipment, which, if it is heavy enough, can absorb the excess energy without allowing system frequency to surge to a damaging level. Inverter-based generators do not provide this benefit and are not credited with reliability values based in Inertia.

All units are expected to be equipped with voltage control and to be able provide or consume ***VARs***. However, without battery storage, solar units have limited ability to provide VAR support without also providing energy to the system. Their ability to provide VAR support is also limited by their intermittency. Their VAR score is reduced accordingly.

Due to independence from pipelines and smaller project sizes, batteries and solar are credited with more ***Geographic Diversity*** than other utility-scale generation. But offsetting this advantage is solar intermittency, which creates the need to use ancillary services to support solar and increases the need for additional reserves from other units. Because it is a deduction that applies to only one resource, the intermittency cost of solar is not separately stated as a reliability factor, but it is accounted for in Dispatchability and Operational Flexibility.

Smaller fossil units, including DESC's gas-fired boilers, ICTs, future ICTs, and batteries can be sited close to load centers. Due to space requirements and land use issues, other generation sources typically cannot be. This results in a credit for providing reliability benefits due to ***Proximity to Load.***

Aeroderivative turbines and battery storage have ***Black Start*** capabilities which allow them to make restoration possible when the system must be recovered from blackout conditions. Aeroderivative turbines have superior black start capability because of the inertia they can provide to stabilize the system during start up. Inverter based resources do not.

Synchronous Condensing is the ability to provide voltage control (VAR support) when the unit is not actually generating electrical current. This allows the unit to provide voltage support without displacing other generation, which can be valuable for stabilizing voltage without affecting power flows or frequency.

The size of a unit, in MW, determines the size of the contribution it can make to system reliability by providing ancillary services, peak capacity, or other grid support. In computing each generating resources' ability to support reliability, its raw reliability score is adjusted according to its nameplate capacity. Battery and solar resources are normalized at 1.0 for each 100MW block. If larger blocks are added, the score is pro-rated by treating each 100 MW of capacity as a separate unit. The Williams and Wateree coal plants are 600+MW and are normalized with a factor 6.0 to take into account the reliability impacts of their retirements. Other units' ratings are adjusted similarly.

Dominion Energy

Our Company

Resource Plan Analysis

Reliability Factors by Resource Type

Unit Type	Coal Unit	Gas-fired Boiler	CC	Large Frame ICT	Aero ICT	Battery	Battery PPA	Flexible Solar	Solar PPA
Scale 1 - 4 used to convey both relative importance of each attribute and how well the resource provides that attribute									
Reliability Factor									
Energy Storage						1	1		
Energy Duration	4	4	4	4	4	1	1	1	1
Dispatchability	2	2	2	2	2	2	2		
Op Flexibility	1	1	2	2	3	2	2		
Coincident Peak Output	4	4	4	4	4	3	3		
Automatic Generation Control	2	3	4	2	2	3	3	1	1
Fast Start					1	1	1		
Inertia (non-inverter)	3	3	3	2	1				
VAR support	2	2	2	2	2	2	2	1	1
Geographic Diversity						1	1	1	1
Proximity to Load	1	1			1	1	1		
Synchronous Condensing					1				
Blackstart					2	1	1		
Total	19	20	21	18	23	18	18	4	4
Comparative Size*	6.0	1.0	5.5	5.2	1.3	1.0	1.0	1.0	1.0
Total Points	114	20	116	94	30	18	18	4	4

* Normalizes the comparison to standard value per 100MWs

Resource Plan Analysis

The following chart provides the reliability contribution rating by generating resource. A higher number indicates a greater contribution to reliability.

Units Added/Retired by Resource Plan

	Coal Unit	Gas-fired Fossil-Steam	CC	Large Frame ICT	Aero ICT	Battery	Battery PPA	Flexible Solar	Solar PPA
RP1	-2		1	4					
RP2	-2			5					
RP3	-2		1	4					
RP4	-2	-3		5					
RP5	-2		1	3		1		4	
RP6	-2			4				4	
RP7	-2			4		1			4
RP7a	-2			5					4
RP7b	-2			4			1		4
RP8	-2		1	1	3	7		19	

With the comparative size adjustment in place, the reliability factors for all new and retired resources are accounted by resource type within each resource plan. The units to be added or retired in each plan are as follows:

Net Change in Reliability Factors in each Resource Plan as of Plan Year 2049

	Coal Unit	Gas-fired Boiler	CC	Large Frame ICT	Aero ICT	Battery	Battery PPA	Flexible Solar	Solar PPA	Combined Factors	Ranking
RP1	-228	0	115.5	374.4	0	0	0	0	0	261.9	2
RP2	-228	0	0	468	0	0	0	0	0	240	7
RP3	-228	0	115.5	374.4	0	0	0	0	0	261.9	2
RP4	-228	-60	0	468	0	0	0	0	0	180	13
RP5	-228	0	115.5	280.8	0	18	0	16	0	202.3	8
RP6	-228	0	0	374.4	0	0	0	16	0	162.4	14
RP7	-228	0	0	374.4	0	18	0	0	16	180.4	10
RP7a	-228	0	0	468	0	0	0	0	16	256	5
RP7a2	-228	0	0	468	0	0	0	0	16	256	5
RP7a3	-228	0	0	468	0	0	0	0	16	256	5
RP7b	-228	0	0	374.4	0	0	18	0	16	180.4	10
RP7b2	-228	0	0	374.4	0	0	18	0	16	180.4	10
RP7b3	-228	0	0	374.4	0	0	18	0	16	180.4	10
RP8	-228	0	115.5	93.6	89.7	126	0	76	0	272.8	1

Dominion Energy

By tracking the changes in generation assets by resource type in the plans over the planning horizon and accounting for the sum of those individual changes over approximately 30 years, this metric provides an estimate of the cumulative reliability impact for each plan. This provides a systematic and quantitative approach to consider the performance of each plan under many scenarios. The sum of reliability factors in each resource plan is calculated, and the plans are ranked as set forth in the chart to the right.

The rankings show that, net of retirements, the resources added under RP8 make the greatest contribution to system reliability of any set of resources modeled. RP2 and RP3 are tied for second place. Having retired existing coal generation early in the planning period, RP8 provides for the addition of combined cycle generation, large-frame ICTs, aeroderivative ICTs, battery storage and flexible solar. The evaluation shows that this diverse and well-balanced set of resource additions makes a uniquely valuable contribution to system reliability.

DESC will continue to evaluate metrics for quantifying the effects on system reliability from different resource plans. This will be a topic for consultation with the IRP Stakeholders Advisory Group and presentations in future IRP updates.

Mini-Max Regret

A Mini-Max Regret measure has been computed as required by Order No. 2020-832. The Mini-Max Regret analysis evaluates each resource plan against the lowest cost plan in each scenario and calculates the difference in the 40-year levelized NPV between the plans. The maximum change from the best plan in each scenario sets the max regret score for each resource plan. Using this metric RP8 received the best score with RP3 being the second best.

There are several caveats that apply to the Mini-Max Regret analysis. The first is that this analysis weights the results under all scenarios and sensitivities equally and so assumes that all scenarios and the sensitivities are equally likely. This is not the case. For this reason, this approach gives the unlikely outcomes more influence over the results than is reasonable or appropriate.

Specifically, in this example, the $35/ton CO_2 plus Low Gas scenario sets the max regret level for every scenario except RP8. As discussed above, the EIA used the $35/ton CO_2 case to stress its analysis and disclaimed any inference that its assumed CO_2 costs should be considered a reasonably probable forecast. Making that highly improbable scenario the standard against which other scenarios are judged dramatically lessens the efficacy of the Mini-Max Regret measure.

Mini-Max Regret Analysis

Resource Plan ID	Resource Plan	Ranking	Max Regret
RP1	CC	10	185,299
RP2	ICT	13	216,565
RP3	Retire Wateree	2	146,124
RP4	Retire McMeekin	14	237,590
RP5	Solar + Storage	12	206,390
RP6	Solar	11	200,926
RP7	Solar PPA + Storage 2026	3	171,398
RP7a	Solar PPA 2023	9	185,152
RP7a2	Solar PPA 2023	8	183,253
RP7a3	Solar PPA 2023	7	181,962
RP7b	Solar PPA + Storage 2023	6	174,800
RP7b2	Solar PPA + Storage 2023	5	172,902
RP7b3	Solar PPA + Storage 2023	4	171,610
RP8	Retire Coal	1	129,897

Cost Range Analysis

A Cost Range Analysis has been computed as required by Order No. 2020-832. The Cost Range Analysis evaluates the variation in the 40-year levelized NPV for each plan across the 27 scenarios that were modeled. The cumulative variation sets the raw score.

This analysis has the same methodological flaw as the Mini-Max Regret analysis. It weights the results under all scenarios and sensitivities equally and so assumes that all scenarios and the sensitivities are equally likely. It gives the unlikely outcomes a level of influence over the results that is not reasonable or appropriate.

Using this metric RP8 received the best score. RP3 scores the second best.

Cost Range Analysis

Cost Range RP ID	Resource Plan Name	Rank	Max-Min
RP1	CC	10	1,214,728
RP2	ICT	14	1,258,235
RP3	Retire Wateree	2	1,196,956
RP4	Retire McMeekin	13	1,252,372
RP5	Solar + Storage	12	1,223,687
RP6	Solar	11	1,216,316
RP7	Solar PPA + Storage 2026	9	1,213,411
RP7a	Solar PPA 2023	6	1,212,024
RP7a2	Solar PPA 2023	8	1,212,024
RP7a3	Solar PPA 2023	7	1,212,024
RP7b	Solar PPA + Storage 2023	3.5	1,208,036
RP7b2	Solar PPA + Storage 2023	5	1,208,036
RP7b3	Solar PPA + Storage 2023	3.5	1,208,036
RP8	Retire Coal	1	1,049,897

Resource Plans Ranked Across All Scenarios

As directed by Order No. 2020-832, DESC has evaluated the fourteen resource plans against all 27 scenarios without distinguishing between those scenarios which are within reasonable possibility and those which are not. This presents the same methodological concerns in this context as the Mini-Max Regret and the Cost Range analysis. Unlikely outcomes assert a level of influence over the results that has the potential to skew results.

Risk and Uncertainty - All Scenarios									
RP ID	Resource Plan Name	40 Year Levelized NPV	2049 CO_2 (Tons Emitted)	2049 Clean Energy	Average Fuel Costs	Generation Diversity	Reliability	Mini-Max Regret	Cost Range
RP1	CC	10	3	13	6	4	3	10	10
RP2	ICT	13	13	14	13	13	7	13	14
RP3	Retire Wateree	6	4	13	12	4	3	2	2
RP4	Retire McMeekin	14	14	11	14	14	13	14	13
RP5	Solar + Storage	11	2	5	1	2	8	12	12
RP6	Solar	12	12	6	10	11	14	11	11
RP7	Solar PPA + Storage 2026	2	5	10	5	7	11	3	9
RP7a	Solar PPA 2023	9	10	3	8	11	5	9	6
RP7a2	Solar PPA 2023	8	10	3	8	11	5	8	8
RP7a3	Solar PPA 2023	7	10	3	8	11	5	7	7
RP7b	Solar PPA + Storage 2023	5	7	8	3	7	11	6	4
RP7b2	Solar PPA + Storage 2023	4	7	8	3	7	11	5	5
RP7b3	Solar PPA + Storage 2023	3	7	8	3	7	11	4	4
RP8	Replace Coal	1	1	1	11	1	1	1	1

RP8 ranks first in seven of eight of the evaluation metrics considered here. No other plan scores nearly as well. While mathematical calculations can never solely take the place of informed judgment and the appropriate balancing of multiple factors, these results clearly point to the superiority of RP8 over other plans as the most reasonable and prudent plan for the DESC to pursue at this time.

When comparing RP5 to RP6 and RP7a to RP7b it becomes obvious that adding battery storage greatly improves the value of solar, although none of these plans are ranked more highly than RP8 and RP1 in terms of overall customer value as measured by the 40-year net present value metric. Resource plans that include solar and battery storage outscore those that include only solar by a significant margin. This is an expected outcome of adding more solar to a system that already has solar capacity greater than 20% of its retail load and where incremental solar generation has negligible if any capacity value. While the Average Ranking presented in the Resource Plan Performance Table currently applies equal weightings to each evaluation category, DESC recognizes that further development will need to be evaluated for future IRPs. Additional performance metrics may be established, and weightings considered based on importance of relative risk metric. DESC will consider a more sophisticated risk-adjusted matrix in its 2022 IRP Update in consultation with the IRP Stakeholder Advisory Group.

The Expected Case Scenario

DESC has also prepared what it believes to be a potentially more suitable comparative ranking of the resource plans. This ranking focuses on the most likely set of scenarios, which are High DSM, $12/ton CO_2 and Low Gas.

- High DSM reflects the Company's expectation that DSM programs can be designed to achieve a 1% reduction in load growth among eligible customers so long as cost effective and non-cost effective programs can be combined in a suite of programs that is cost effective in aggregate.
- The $12/ton CO_2 assumption is based on a carefully researched and reasoned forecast from a globally respected economic forecasting firm (IHS). The low alternative, $0/ton, is unlikely given societal expectations and the expected policies of the Biden Administration. The $35/ton EIA assumption is not a true forecast but a parameter chosen to stress the EIA reference case. Through compounding, the 7.5% escalation rate, which begins in 2021, leads to CO_2 costs for customers of $255 per short ton by the end of the period, a level that is excessively high and outside of what would be likely be supported as reasonable. The $35/ton case assumes that this CO_2 price is imposed beginning in 2021, which is not likely. Coupling a high initial cost, early imposition and robust escalation results in CO_2 costs over the planning period that are unreasonably high.
- The EIA Low Gas case most closely aligns with current markets, which are significantly below the alternatives. The High and Medium EIA gas scenarios are based on gas prices that posit restrictions on the availability of natural gas supplies that appear to be inconsistent with the volume of natural gas that is available to be produced from private lands, and the value to the national economy of maintaining low cost, abundant supplies of natural gas.

The Expected Case Scenario Results

DESC has calculated the results under the Expected Case scenario across six metrics, Levelized Cost, CO_2 Emissions, Clean Energy, Fuel Costs and Generation Diversity and Reliability. Mini-Max Regret and Cost Range were omitted because of their methodological flaws and because by nature they measure results across multiple scenarios and do not apply where a single scenario is evaluated. The result of this evaluation of the performance of the plans is as follows:

Expected Conditions --High DSM, $12/ton CO_2, Low Gas-							
RP ID	Resource Plan Name	40 Year Levelized NPV	2049 CO_2 Emitted	2049 Clean Energy	Average Fuel Costs	Generation Diversity	Reliability
RP1	CC	8	4	12	3	4	3
RP2	ICT	12	13	13	13	13	7
RP3	Retire Wateree	3	4	12	4	4	3
RP4	Retire McMeekin	14	14	14	14	14	13
RP5	Solar + Storage	11	2	6	1	2	8
RP6	Solar	13	5	10	11	11	14
RP7	Solar PPA + Storage 2026	2	12	2	12	7	11
RP7a	Solar PPA 2023	10	7	8	6	11	5
RP7a2	Solar PPA 2023	9	7	8	6	11	5
RP7a3	Solar PPA 2023	7	7	8	6	11	5
RP7b	Solar PPA + Storage 2023	6	10	4	9	7	11
RP7b2	Solar PPA + Storage 2023	5	10	4	9	7	11
RP7b3	Solar PPA + Storage 2023	4	10	4	9	7	11
RP8	Replace Coal	1	1	1	2	1	1

Out of fourteen resource plans, RP8 has the top rating under five of these six metrics: levelized cost, CO_2 reduction, clean energy, generation diversity and reliability. It ranks second against the one remaining metrics: average fuel cost. It outscores all other plans by a large margin. RP5 is the only plan that has more than one first or second place ranking. It ranks first in average fuel cost, and second in CO_2 emitted and generation diversity.

The Preferred Plan

Mathematical calculations such as those presented here can be properly used to inform the evaluation of potential resource plans. But they do not take the place of the careful consideration and balancing of multiple factors using sound utility judgement and knowledge of an individual utilities' operating characteristics and service territory.

RP8 assumes that Wateree and Williams Stations are retired in 2028 and the sole remaining coal unit, the dual-fuel Cope Station, is converted to natural gas firing only in 2030. For this reason, it does especially well in those scenarios that assume regulatory costs are imposed on CO_2 emissions, which is an increasingly likely possibility. It also insulates the system against the risk of other regulatory and environmental changes affecting coal generation. These are important considerations. RP8 reflects by far the greatest reduction in CO_2 emissions of any resource plan (approximately 60% compared to 2005 emissions). It is the plan that is most consistent with a zero net carbon emissions future.

RP8 also performs well under the assumption that natural gas markets are not unduly constrained in future years and natural gas prices remain in the low or moderate forecasted range during the planning period. This seems to be a reasonable assumption given current levels of natural gas supplies.

By retiring coal units earlier than other plans, RP8 causes the system to increase its reliance on natural gas earlier than other plans. This can result in increased costs in a high-gas cost environment. However, the alternative is to assume continued reliance on coal which may be an even riskier assumption. Although RP8 requires earlier additions of gas resources to support coal retirements, its total gas requirement over the long term is lower than all other plans given the quantity of renewable resources it envisions adding to the system.

Based on its analysis and evaluation of these data and these plans, DESC has determined that RP8 represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is filed. RP8 is DESC's preferred plan, and its superior scores on multiple key metrics clearly supports that conclusion.

The costs and reliability impacts of coal plant retirements envisioned under RP8 are yet to be fully be quantified through station-specific retirement studies. RP8 will be reevaluated in light of the coal retirement studies that are being undertaken in early 2021 through 2023 and in light of conditions in natural gas markets as they evolve. No definitive decisions concerning large new resource procurements are required in the immediate time frame, allowing time for further data collection and study of these alternatives. The design of ELG solutions for Wateree and Williams Stations is ongoing and will inform the retirement studies for each facility. But no major construction commitments are envisioned for some time.

Forecast of Renewable Generation

All resource plans include a significant amount of renewables, between 7% and 19% of total generation at the end of the forecast period. The values in the table show the total renewable generation by resource plan by five-year period for the High DSM, Low Gas, and \$12/ton CO_2 scenarios only. Similar data for the Low and Medium DSM scenarios are provided in **Appendix L**.

Dominion Energy

Our Company

Resource Plan Analysis

Energy from Renewable Generation Summed by Five-Year Period (High DSM, Low Gas, and \$12/ton CO_2) (GWh)							
RP ID	**Resource Plan Name**	**2020-2024**	**2025-2029**	**2030-2034**	**2035-2039**	**2040-2044**	**2045-2049**
RP1	CC	9,481	10,169	10,168	10,168	10,178	10,160
RP2	ICT	9,481	10,169	10,168	10,168	10,178	10,160
RP3	Retire Wateree	9,481	10,169	10,168	10,168	10,178	10,160
RP4	Retire McMeekin	9,481	10,169	10,168	10,168	10,178	10,160
RP5	Solar + Storage	9,481	13,133	13,994	14,092	14,206	14,297
RP6	Solar	9,481	13,133	13,991	14,080	14,216	14,298
RP7	Solar PPA + Storage	9,481	13,132	13,995	14,093	14,223	14,300
RP7a	Solar PPA + Storage	10,986	13,865	13,988	14,075	14,220	14,298
RP7b	Solar PPA + Storage	10,998	13,872	13,998	14,096	14,213	14,301
RP8	Replace Coal	9,481	10,852	14,222	19,151	24,121	28,502

Rate and Bill Impacts

Section 58-37-40(C)(2)(b) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of consumer affordability and least cost. Order No. 2020-832 further required DESC to calculate rate and bill impacts of its various portfolios in the Modified 2020 IRP. In compliance with Order No. 2020-832, DESC has created an estimate of the Retail Rate Impact for each plan. This analysis uses the same incremental cost data that was used in preparing the Levelized Cost for each resource plan. Rate impacts were computed using the load growth forecasts and fuel cost forecasts embedded in the various scenarios. The analysis then combined that data with data concerning existing rates and cost of service allocators between rate classes. This made it possible to compute the impacts of resource plans on the monthly bill for a typical 1,000 kWh residential customer for each year from 2020 to 2034. The rate impact analysis is not a forecast of future rates, but a calculation for comparative purposes of the incremental dollar impact of each resource plan on a residential customers' monthly bill, all other things being equal. The analysis does not attempt to model other changes to residential rates or bills.

Both the Levelized Cost metric and Retail Rate Impact analysis measure costs that would be borne by customers. But they differ in that the Levelized Cost metric measures costs over a 40-year asset life, not fifteen years like the rate impact analysis presented here. In resource planning, 40-year impacts are the more appropriate impacts to be considered in evaluating and ranking resource plans. Long-lived generation assets reduce costs and provide customer benefits over decades. A 40-year period more closely matches the useful lives of those assets and ensures that the full cost and benefits of investing in them are captured but the analysis.

Dominion Energy

Bill impacts for the typical residential customer for each of the fourteen resource plans are provided in the chart below in dollar terms. The rate impacts in dollars are given for the High DSM, \$12/ton CO_2 and Low Gas price case. Rate impacts for the other cases are provided in **Appendix M.**

Typical Residential Bill @1000 kWh/month (Medium DSM, \$12/ton CO_2, Low Gas)															
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
RP1	122.31	127.28	129.59	131.49	132.86	134.56	140.57	142.52	144.62	147.72	155.17	155.78	160.48	164.00	167.91
RP2	122.31	127.28	129.59	131.49	132.86	134.56	140.57	142.52	144.62	147.72	155.17	155.78	160.48	164.00	167.44
RP3	122.31	127.28	129.59	131.49	132.86	134.56	139.16	141.15	144.15	154.90	161.59	161.75	165.73	169.43	177.05
RP4	122.31	127.28	129.59	131.49	132.86	134.56	140.57	142.52	145.00	151.36	159.07	159.93	164.18	167.99	170.55
RP5	122.31	127.28	129.59	131.49	132.86	134.56	144.89	146.64	148.64	151.27	158.35	159.21	163.56	167.23	169.93
RP6	122.31	127.28	129.59	131.49	132.86	134.56	143.85	145.64	147.71	150.37	157.49	158.30	162.73	166.34	169.04
RP7	122.31	127.28	129.59	131.49	132.86	134.56	142.04	143.99	146.10	148.83	156.00	156.92	161.37	165.04	167.81
RP7a	122.31	127.28	129.59	132.57	133.84	135.57	141.50	143.49	145.68	148.43	155.66	156.54	161.06	164.69	167.46
RP7a2	122.31	127.28	129.59	132.43	133.70	135.43	141.36	143.35	145.54	148.29	155.52	156.40	160.92	164.55	167.32
RP7a3	122.31	127.28	129.59	132.34	133.61	135.34	141.27	143.26	145.45	148.20	155.43	156.31	160.83	164.46	167.23
RP7b	122.31	127.28	129.59	132.91	134.37	136.01	142.02	144.02	146.16	148.90	156.09	157.04	161.52	165.18	167.95
RP7b2	122.31	127.28	129.59	132.77	134.23	135.87	141.88	143.88	146.02	148.76	155.95	156.90	161.38	165.04	167.81
RP7b3	122.31	127.28	129.59	132.68	134.14	135.78	141.79	143.79	145.93	148.67	155.86	156.81	161.29	164.95	167.72
RP8	122.31	127.28	129.60	131.39	132.90	134.56	137.87	140.33	143.70	157.90	165.86	167.24	171.09	175.13	178.63

Dominion Energy

Our Company

Resource Plan Analysis

The charts that follow provide the retail rate impact of each of the fourteen resource plans. Retail rate impacts show the impact on retail rates collectively for all customers on a cents/kWh basis.The rate impacts are given for the High DSM, \$12/ton CO_2 and Low Gas price case. Rate impacts for the other cases are provided in **Appendix N**.

Retail Rate Impact (cents/kWh)															
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
RP1	0.09775	0.10181	0.10362	0.10535	0.10647	0.10795	0.11316	0.11487	0.11668	0.11950	0.12670	0.12713	0.13148	0.13472	0.13821
RP2	0.09775	0.10181	0.10362	0.10535	0.10647	0.10795	0.11316	0.11487	0.11668	0.11950	0.12670	0.12713	0.13148	0.13472	0.13783
RP3	0.09775	0.10181	0.10362	0.10535	0.10647	0.10795	0.11204	0.11377	0.11631	0.12504	0.13157	0.13163	0.13534	0.13873	0.14527
RP4	0.09775	0.10181	0.10362	0.10535	0.10647	0.10795	0.11316	0.11487	0.11699	0.12230	0.12981	0.13054	0.13447	0.13805	0.14039
RP5	0.09775	0.10181	0.10362	0.10535	0.10647	0.10795	0.11642	0.11797	0.11971	0.12208	0.12894	0.12964	0.13365	0.13705	0.13951
RP6	0.09775	0.10181	0.10362	0.10535	0.10647	0.10795	0.11560	0.11718	0.11899	0.12139	0.12828	0.12893	0.13302	0.13637	0.13882
RP7	0.09775	0.10181	0.10362	0.10535	0.10647	0.10795	0.11416	0.11587	0.11770	0.12016	0.12709	0.12785	0.13195	0.13534	0.13786
RP7a	0.09775	0.10181	0.10362	0.10606	0.10708	0.10858	0.11372	0.11546	0.11736	0.11983	0.12681	0.12752	0.13169	0.13505	0.13756
RP7a2	0.09775	0.10181	0.10362	0.10596	0.10698	0.10848	0.11362	0.11536	0.11726	0.11973	0.12671	0.12742	0.13159	0.13495	0.13746
RP7a3	0.09775	0.10181	0.10362	0.10588	0.10690	0.10840	0.11354	0.11528	0.11718	0.11965	0.12663	0.12734	0.13151	0.13487	0.13738
RP7b	0.09775	0.10181	0.10362	0.10629	0.10750	0.10892	0.11413	0.11588	0.11773	0.12019	0.12713	0.12791	0.13203	0.13541	0.13793
RP7b2	0.09775	0.10181	0.10362	0.10618	0.10739	0.10881	0.11402	0.11577	0.11762	0.12008	0.12702	0.12780	0.13192	0.13530	0.13782
RP7b3	0.09775	0.10181	0.10362	0.10611	0.10732	0.10874	0.11395	0.11570	0.11755	0.12001	0.12695	0.12773	0.13185	0.13523	0.13775
RP8	0.09775	0.10181	0.10362	0.10524	0.10650	0.10794	0.11097	0.11307	0.11590	0.12736	0.13468	0.13569	0.13918	0.14275	0.14583

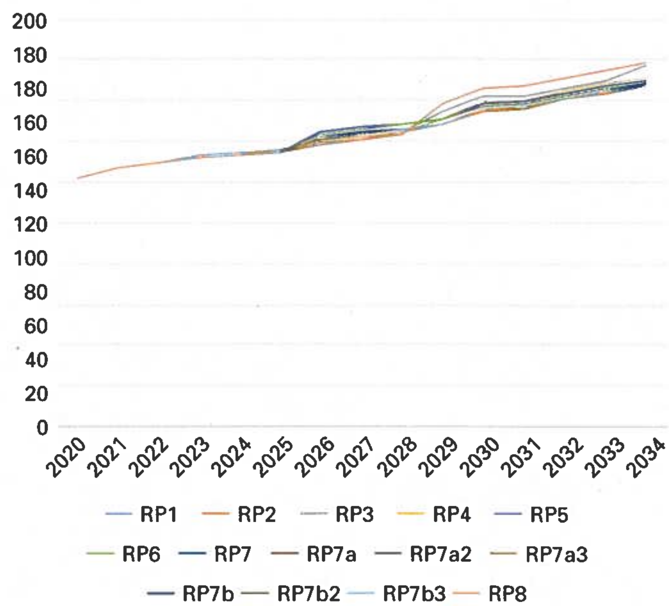
Dominion Energy

Our Company

Resource Plan Analysis

The lowest retail impacts are widely scattered with RP1, 2, 7, 7a2 and 7a3 and 8 having the lowest rate impacts under different scenarios. This reflects the facts that the results are tightly bunched, and the resource plans result in broadly similar rates. Under most of these analyses, the difference in retail rates at the end of fifteen years is on the order of 10% or less between the highest and lowest rate plans.

Typical Residential Bill High DSM, $12/ton CO_2, Low Gas



Dominion Energy

Our Company

Short-Term Action Plan

This short-term action plan presents steps that the Company intends to take in implementing its Modified IRP for the next three years (2021 to 2023).

Columbia, South Carolina

This Short-Term Action Plan ("STAP") presents steps that the Company intends to take in implementing its Modified IRP for the next three years (2021 to 2023).

Monitoring of Supply Side Decision Points

During the three-year scope of this plan, the Company will carefully monitor changes affecting future generation plans. These changes include changes in natural gas prices, regulatory and legislative requirements regarding CO_2 emissions, the costs of renewable and energy storage technologies, access to natural gas supplies and transmission capabilities and developments in other environmental policies and novel generating technologies.

At present, the Company's reserve margins are fully sufficient to meet customers' capacity needs in the near term. Furthermore, the Company's recent acquisition of approximately 973 MW of solar PPAs, coupled with low-priced natural gas supplies, have reduced the Company's 10-year avoided energy costs to about $30/MWh for non-solar resources and a lower value would be calculated for a solar profile. Because of DESC's low current marginal cost of energy, additional renewable resources are unlikely to result in fuel cost savings for customers in the short run. The modeling of RP7a 1-3 and RP7b 1-3 clearly show this to be the case.

However, the Company will continue to evaluate current resources to determine if continued operation is in the customers' best interest. The retirement studies for coal and fossil-steam units are underway and will be conducted using resource optimization software after developing cost estimates and other inputs reviewed with the IRP Stakeholder Advisory group. If a sustained increase in natural gas prices or other fossil fuels were to occur or if implementing reductions in CO_2 emissions became advisable as a matter of environmental compliance or regulatory policy, a shift in the Company's strategic direction related to system supply could be warranted. The Company intends to carefully monitor these conditions and inform its planning accordingly.

In the very near-term, it is in customers' best interest for the Company to continue operating its existing portfolio of renewable, fossil and nuclear generation resources while the Company executes its plans to:

- Enhance IRP Advisory Stakeholder Group process,
- Finalize the implementation of the PLEXOS resource optimization model (after consultation from the IRP Stakeholder Advisory Group) for use in conducting retirement studies,
- Reevaluate (in consultation with the IRP Stakeholder Advisory Group) its approach to key planning inputs like natural gas prices, future customer demands including electric vehicle adoption, environmental constraints and the cost of renewables and storage,

- Review its DSM portfolio for the potential to increase reductions in sales growth, and
- Implement new demand reduction programs made possible by AMI.

The results of these efforts will feed into the retirement studies for Wateree Station, Williams Station, the other fossil-steam units and Cope Station. They will also shape the 2021 and 2022 IRP Updates and the 2023 IRP.

The 2020 Resource Plans and Their Role in This Implementation Approach

The Company intends to update or revise its IRP annually to reassess its designation of the preferred resource plan in light of potentially changing market conditions and state or federal environmental laws or regulations. At the core of this short-term action plan is the Company's intention to monitor changes in these variables and update the IRP annually to reflect those changes.

Generation Retirement Planning

The Company has retired or repowered eight of its twelve coal units in the last eighteen years and recommissioned dual-fuel capability at one of the remaining four stations. The Company intends to perform retirement studies on the three coal units at Wateree and Williams Stations during the three-year scope of this plan. The Company is initiating a retirement study for Wateree Station, which is the largest of the three remaining coal fired stations on its system, in early 2021. As required by Order No. 2020-832, DESC intends to complete retirement studies for Wateree Station, Williams Station and Cope Station during the second year of the three-year short-term action plan. The studies for these five units at three sites can be completed within this Short-Term Action Plan period.

Concurrently, the Company will also schedule retirement planning for three older units, Urquhart Steam Unit 3 and McMeekin 1 and 2, that were converted from coal to natural gas status in 2013 and 2015, respectively.

Once a timeline for the potential retirement of Wateree Station is determined and replacement resources are identified, a retirement study for Williams Station can be initiated. When that study is completed, a retirement study for Cope Station can begin. The timeline for all studies depends largely on the workload of the Transmission Planning Department, which is anticipated to require the longest lead-time to complete its analysis. The Transmission Planning Department can begin its work when the Power Generation and the Resource Planning groups identify the operating parameters of any replacement generation that will be required during the transmission planning horizon. DESC will consult with the IRP Stakeholder Advisory Group throughout the process. Determining the optimal date for resource retirement will require the resource optimization software to be fully implemented. That is anticipated to be completed in early 2021 subject to consulting with the IRP Stakeholder Advisory Group concerning alternative software as required by Order No. 2020-832.

Generally, each retirement study will:

- Identify decommissioning and site restoration costs
- Identify replacement generation and operating parameters
- Determine scope and cost of transmission investments
- Make retirement recommendation
- Implement retirement decision
- Update planning models to reflect retirement decision
- Commence a retirement study for the next candidate

These steps will take months and years and each study will inform the next. These will be sequenced as follows:

1. Wateree 1 and 2
2. Williams
3. Cope

Studies that may be completed concurrently with Wateree and Williams:

1. Urquhart 3
2. McMeekin 1 and 2
3. Hagood ICTs

Peaking Turbine Modernization Program

The inclusion of approximately 973 MW of intermittent solar generation on the Company's system and normal operational contingencies have placed additional demands on its aging fleet of simple cycle combustion turbines. The Company's current fleet of simple cycle combustion turbines includes a number of units that are at or nearing the end of their expected useful lives for units of this type. Many of these units were originally constructed for intra-day peaking on a seasonal basis and for system blackstart capabilities; they were not designed as resources to be called on for daily intra-day peaking duty. The Company is completing its evaluation of the replacement of certain older units with modern aero-derivative replacements. These modern units have reliability and efficiency advantages that become even more important as additional intermittent resources are added. The new units would be uniquely capable of responding to unanticipated fluctuation in generation resources on the system caused by the interaction of solar generation with changing weather conditions.

Once decisions concerning the number, technology and location of the replacement units have been made, the Company anticipates filing an application with the Commission for a ruling affirming that these replacements can proceed under the provisions of the South Carolina Facility Siting and Environmental Compliance Act that apply to the replacement of existing resources. Procurement and construction of the units would follow the issuance of such a ruling.

- Determine optimal number, location and technology of replacement peaking turbines
- File for Commission affirmation of like-facilities replacement under the Siting Act (as applicable)
- Proceed to engineering, procurement and construction of the new units

Demand-Side Management

Initiate a Rapid DSM Expansion for Implementation in 2021

At DESC's request, its DSM consultant, ICF, completed a further review of the rapid assessment of DSM expansion potential as directed by Order No. 2020-382. This further review has determined that an expanded DSM program achieving a 1% reduction in demand growth from eligible customers is possible. The design of this expanded suite of programs was completed too late for it to be fully included in this 2020 Modified IRP.

- Conduct stakeholder consultations
- Finalize rapid assessment and include in the Modified 2020 IRP
- Begin a collaborative process working with the EE Advisory Group to conduct a comprehensive DSM evaluation
- Prepare 2023 IRP Filing with EE Advisory Committee Input into the comprehensive DSM evaluation

Prepare the 2023 DSM Update

As required by Order No. 2020-832, DESC will evaluate the cost-effectiveness and achievability of DSM portfolios reaching 1% and higher savings, including savings levels of 1.25%, 1.5%, 1.75% and 2% for inclusion in its next full IRP, to be filed in 2023.[8] DESC intends to seek approval of the DSM action plan discussed above and then begin the RFP process for the next potential study. DESC will include the EE Advisory Group throughout this process and provide opportunities for iterative review, input and feedback. New to the EE Advisory Group for this process are the Energy Futures Group, an environmental group, and the SC Association of Community Action Partnerships, which represents low income residents.

By the third quarter of 2021, DESC plans to select a vendor and initiate the potential study for a comprehensive DSM evaluation for the 2023 DSM update in consultation with the EE Advisory Group. In the following quarter, DESC will hold a kick-off meeting with EE Advisory Group to discuss scope and process for potential study. The EE Advisory Group will receive status reports during regularly scheduled meetings at least twice per year and will receive a final draft of the 2023 DSM Plan for input prior to finalization of the potential study.

- Conduct initial EE Advisory Group consultations
- Select consultant
- Scope studies in consultation with EE Advisory Group
- Conduct DSM study with regular updates to EE Advisory Group
- Prepare draft DSM report and receive EE Advisory Group input
- Present petition to Commission for approval of 2023 updated DSM plan
- Implement plan

Complete AMI Roll-Out and Implement Residential and Commercial Demand Reduction Programs

Before the end of this three-year period, the Company expects to have completed the installation of sufficient AMI meters on its system so that it can begin the process of preparing a new potential study and implementation plan specifically targeted toward the addition of new residential and commercial demand reduction programs to DESC's tariffs and DSM program. The potential study for new residential and commercial demand reduction programs will be part of the 2023 potential study.

- Complete installation of AMI meters
- Collect data to inform a demand reduction potential study
- Consult with the EE Advisory Group
- Instruct DSM consultant conduct potential study and propose programs
- Consult with EE Advisory Group concerning potential study and proposed programs
- Present petition to Commission to amend tariffs/DSM programs to provide new residential and commercial demand reduction programs
- Implement amended tariffs/DSM programs suite upon approval by the Commission

[8] DESC would note that Order No. 2020-832 provides both a 2022 and 2023 deadline for the comprehensive DSM evaluation. Given that the next full IRP is to be filed in 2023, DESC assumes that the 2023 deadline applies, and the 2022 deadline was misstated. Additionally, to complete a comprehensive DSM evaluation with stakeholder involvement, 2023 is the more practical deadline.

Changes to the IRP Planning Process

In the beginning of the three-year scope of this plan, the Company intends to conduct a comprehensive review of its IRP planning software and inputs. An initial step in this process will be the consultation with its IRP Stakeholder Advisory Group concerning its software choice going forward and implementation of that resource optimization software. DESC will also conduct a review of model inputs and forecasts in consultation with its IRP Stakeholder Advisory Group and will implement a robust advisory process for consultation on future IRP filings.

Implement Resource Optimization Software

In a project that began in early 2020, and with assistance of personnel from other Dominion Energy subsidiaries, PLEXOS software has been configured to model the DESC system, and the relevant data and inputs have been included. Quality assurance testing will begin in late February 2021 with the software expected to be ready for use in the second quarter of 2021. PLEXOS will enable DESC to select a single optimal set of resources for each scenario instead of comparing non-optimal resource plans in several scenarios. The inputs in question are distinct from the fuel cost forecasts, CO_2 cost assumptions, capital cost assumption and other modeling inputs discussed elsewhere in this Modified 2020 IRP.

In Order No. 2020-832, and the directive issued on January 20, 2020, in Docket No. 2019-226-E, the Commission directed DESC to consult with stakeholders concerning the appropriateness of employing PLEXOS software compared to alternatives and present its determination to the Commission for review. DESC began consulting with its IRP Stakeholder Advisory Group on February 16, 2021. In the meantime, given the importance of resource optimization software to retirement studies and other work, DESC plans to complete PLEXOS implementation and utilize it pending a contrary decision. DESC also will work with PLEXOS concerning terms for intervenors to access its software and user's manual.

- Conduct stake holder consultations concerning the PLEXOS model
- Work with PLEXOS concerning intervenors' access
- Present results to Commission by April 20, 2021

Reevaluate Key Model Assumption and Forecasts

In parallel with implementing the PLEXOS software, the Company also intends to reevaluate key forecasts, assumption and inputs to the planning model based on comments received from the IRP Stakeholder Advisory Group. Among the inputs the Company intends to evaluate in light of stakeholder comments are its approaches:

a) To summer and winter reserve policy;

b) To reflect VACAR reserve sharing requirements in its capacity reserve margin calculation;

c) To forecast natural gas prices;

d) To forecast demand and energy growth on its system; and

e) The capacity contribution of PV solar toward the Reserve Margin.

The Company also intends to include multiple load growth forecasts and CO_2 price assumptions in its future IRP sensitivity studies and to model a wider range of values for future load growth, CO_2 prices and natural gas prices in future analyses.

- Conduct stakeholder consultations concerning the forecasts, assumptions and other model inputs
- Revise model inputs related to reserve margins, VACAR sharing requirements, fuel prices and demand and energy growth forecasts as indicated
- Present results to Commission in future IRP filings and updates

Implement a Robust IRP Stakeholder Advisory Group Process

In late 2020, DESC retained Charles River Associates to design and implement a robust stakeholder advisory group process. Charles River Associates presided over the initial IRP Advisory Group kick-off meeting on February 16, 2021.

Invitees to this meeting included:

- Office of Regulatory Staff
- SC Energy Office
- Coastal Conservation League
- SC Small Business Chamber of Commerce
- SC Office of Economic Opportunity
- SC Energy Users Committee
- SC Community Action Partnership
- Southern Alliance for Clean Energy
- Johnson Development Associates, Inc.
- South Carolina Solar Business Alliance
- Sierra Club
- AARP South Carolina
- Walmart, Inc.

During this meeting, results of the DSM Rapid Assessment and inputs to the 2020 Modified IRP were reviewed and planning for an effective stakeholder process for the 2021 and 2022 IRP updates was discussed. Stakeholder participation in the 2021 and 2022 IRP updates was then discussed. Key topics for future meetings include:

- Transparency of the IRP analysis;
- Model selection for future IRP work;
- Generator retirement analysis;
- Analysis of PV solar winter capacity value;
- Risk metrics & industry best practices;
- CO_2 and Commodity price scenarios;
- Candidate resource costs; and
- Updates to the DSM portfolio and DSM cases

In the near term, this advisory group process will be used to consult on the selection and implementation of resource optimization software, on changes to model inputs, forecasts and assumption, and on changes in DSM assumptions and programs. In the months prior to an IRP filing or update, this process is contemplated to involve meetings every six to eight weeks to review model inputs and scoping and draft model runs.

- Hire a respected third-party advisory group convener
- Assemble a broad-based and comprehensive IRP Stakeholder Advisory Group
- Establish expectations regarding meetings, agendas and participation standards for the group
- Conduct advisory group consultations concerning the forecasts, assumptions, other model inputs and other matters as IRP studies are being prepared
- Incorporate results in future iterations of the IRP studies
- Present draft result to the advisory group
- Incorporate results of consultation as appropriate in future IRP filings and updates

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Integration of the IRP into Utility Planning

Order No. 2020-832 requires the Company to outline how the IRP integrates into other planning at the Company.

Sunset over Shem Creek in Mount Pleasant, South Carolina.

Order No. 2020-832 requires the Company to outline how the IRP integrates into other planning at the Company. Each IRP identifies a preferred resource plan for planning purposes based on models run by the Resource Planning Department using inputs from the Forecasting group, the DSM group, the Load Research group, Power Generation Department, Nuclear Operations Department, the Fuel Procurement and Asset Management Department, Resource Commitment Department, and the Dominion Energy Services - Project Construction Financial Management and Controls, among others. Changes in the IRP are communicated to these departments to ensure that their planning is based on current information.

In addition, as each IRP is approved, the preferred resource plan and its methodology are used by the Resource Planning Department for calculating avoided energy and capacity costs for projects that qualify as small renewable energy projects under the Federal Public Utilities Regulatory Policies Act, 16 U.S.C. § 796 et seq., and the implementing FERC regulations, 18 C.F.R. § 292.204. The results of these calculations are integrated into PPAs negotiated with renewable project developers by the Power Marketing Department. The resource planning model is also used by the Resource Planning Department and the Rates and Regulatory Department to prepare avoided cost filings presented to the Commission on a twenty-four-month cycle as required by S.C. Code Ann. § 58-41-20.

If the Company's preferred generation plan as identified through the IRP process shows that new generation resources are needed to meet customer load, the Resource Planning Department and Power Generation Department will determine the lead time required to construct and permit those resources and any related fuel supply or transmission assets that are envisioned. At this point, additional departments including the Transmission Planning Department, Power Delivery Business Unit and the Fuel Procurement and Asset Management Department may be consulted. At the appropriate time, a tentative construction decision will be made establishing the size, technology and location of the required resources. The determination will then be made as to whether an all-source RFP for the new generation is required or advisable. The IRP will be updated to reflect these decisions in the next filing.

The decision to proceed with the project will be communicated to the Transmission Planning Department by filing a formal interconnection application under DESC's FERC regulated Open Access Transmission Tariff. Any additional transmission resources required to support the generation plan will be identified by the Transmission Planning Department, which will rely on the Electric Transmission Support Department in consultation with the Power Delivery Business Unit to determine the cost and schedule for construction of those transmission assets. The resulting costs and timelines will be communicated by the Transmission Planning Department to the Resource Planning Department and Power Generation Department for review and incorporation in future IRP filings.

At various stages in this process, the cost and justification for the generation and transmission assets would be reviewed by DESC senior leadership, and by the Investment Review Committee at Dominion Energy, Inc., and its CEO and board which must approve such significant capital expenditures. If a decision is made to construct the assets, those assets will be incorporated in the Transmission Planning Department's reliability and interconnection models and in future IRP filings or annual updates.

Conclusion

Three Palmetto palm trees stand against rustic brick wall in downtown Columbia, South Carolina.

This Modified 2020 IRP indicates, based on balancing a variety of key factors, that the most reasonable and prudent plan for the Company and its customers is RP8. This plan includes Wateree and Williams Stations retirements and addition of low-emitting natural gas, solar and battery storage resources. RP8 is the preferred plan. Specific retirement studies are being prepared that will inform future decision making and will be presented in a future IRP. As mentioned earlier, the Company is also completing an assessment of near term modernization and replacement of some of its older gas-fired generation resources for reliability and operational flexibility. Otherwise, in the near term, the Company does not need to make any major changes to the baseload generation fleet to continue to meet customers' energy and capacity needs in a safe, reliable, and cost-effective manner. This will allow the retirement studies to be completed before new generation procurement decisions are required. In the interim, in an effort to produce a more sustainable future, the Company is upgrading its distribution network with projects like AMI and smart switching; evaluating the replacement of older peaking units with flexible, and reliable quick-start units; expanding its DSM programs and studying its transmission and distribution system to support additional intermittent renewable generation. The deployment of AMI across the system will increase the potential for additional cost-effective DSM programs including new DR programs.

Appendix A: Act 62 Requirements

The details of the IRP requirements under Act No. 62 are shown in the following table along with a reference to each section of the Company's IRP demonstrating compliance:

Act No. 62 58-37-40	Requirement	Modified 2020 IRP Section
(B)(1)(a)	a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	III.A III.B
(B)(1)(b)	the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	VI.C VI.L
(B)(1)(c)	projected energy purchased or produced by the utility from a renewable energy resource;	V
(B)(1)(d)	a summary of the electrical transmission investments planned by the utility;	II.F
(B)(1)(e)	several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i) customer energy efficiency and demand response programs; (ii) facility retirement assumptions; and (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	VI.C VI.D
(B)(1)(f)	data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	I.C
(B)(1)(g)	plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;	VI.C
(B)(1)(h)	an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and	VI.C
(B)(1)(i)	a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	III.A IV.A IV.B IV.C IV.D
(B)(2)	An integrated resource plan may include distribution resource plans or integrated system operation plans.	II.D IV.B

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Appendix B: Commission Order No. 2020-832 Required Modifications

The requirements of this Modified IRP pursuant to Order No. 2020-832 are shown in the following table along with a reference to each section of the Company's Modified IRP demonstrating compliance:

Order No. 2020-832 Page Number	Ordered Modification	Modified 2020 IRP Section
16 (Finding of Fact 2)	It is reasonable that, at the time of the filing of Dominion's Modified IRP, Dominion shall be able [to] indicate to the Commission the composition of current and prospective stakeholders [for the IRP Stakeholder Process], and report on any stakeholder meetings that have occurred prior to the filing date.	VII.F.3
16-17 (Finding of Fact 4)	It is reasonable to require DESC to model a limited set of additional resource plans as specified by SCSBA and to include them in a Modified 2020 IRP filed in this docket within 60 days of the Order.	VI
17 (Finding of Fact 7)	It is reasonable to require DESC, in its Modified 2020 IRP, to build candidate resource plans to meet its full peaking reserve margin target, and the resource plan analysis should determine what type of resources best meet the peaking increment.	VI
18 (Finding of Fact 8)	It is reasonable to require DESC to re-run its IRP modeling using the set of assumptions recommended in SCSBA Witness Sercy's Rebuttal Testimony and Sierra Club Witness Derek Stenclik's Rebuttal Testimony, and to include the results of that modeling in its Modified 2020 IRP.	VI
18-19 (Finding of Fact 11) 64 90 (Ordering Paragraph 6.c)	Cost range and minimax regret analyses are simple, appropriate methodologies that can feasibly be implemented in a Modified 2020 IRP. It is reasonable to require DESC to submit a Modified 2020 IRP including a comparison of candidate resource plans employing simple quantitative risk metrics, including cost ranges and regret scores, as recommended by SCSBA Witness Sercy in his direct and rebuttal testimony. The Commission will require DESC to implement the cost range and minimax regret analyses in the Modified 2020 IRP and subsequent updates and will consider more refined and sophisticated risk-adjusted metrics in its 2022 IRP Update. Conduct and include in the Modified 2020 IRP an analysis and comparison of all candidate resource plans using the simple quantitative risk metrics recommended by SCSBA Witness Sercy in his direct and rebuttal testimony, including cost ranges and minimax regret scores.	VI.I
19 (Finding of Fact 12)	DESC's scenario analysis does not consider a sufficiently wide range of possible load conditions, gas prices, or CO_2 prices. It is reasonable to require DESC to conduct a revised scenario analysis based on modeling that reflects a wider range of possibilities, as proposed by SCSBA. It is also reasonable to require DESC to include the results of this analysis in a Modified 2020 IRP filed in this docket.	VI
19 (Finding of Fact 13) 75-76 91 (Ordering Paragraph 6.e) 91 (Ordering Paragraph 6.d)	Accordingly, the Commission finds it is reasonable to require that DESC work with the DSM Advisory Group ("Advisory Group") to conduct a rapid assessment of the cost-effectiveness and achievability of ramping up its current DSM portfolio, such as by expanding programs or increasing spending, to achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and to require that DESC include this analysis in its Modified 2020 IRP. It is also reasonable to require DESC to include in the Modified 2020 IRP action steps it will take to complete the comprehensive DSM evaluation described in Finding 17 below. The Commission adopts the recommendation in Step 1 of Witness Hill's Late-Filed Exhibit, which directs DESC to conduct a "rapid assessment" of the cost-effectiveness and achievability of ramping up its current portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024. As outlined in step 2 of that exhibit, DESC must work with the Advisory Group in conducting this "rapid assessment" and must include the results of this "rapid assessment" in its Modified 2020 IRP. The Modified 2020 IRP must also include steps the Company will take to complete the "comprehensive evaluation" discussed below in preparation for including such an evaluation in its 2022 IRP. Consistent with step 1 as identified in Hearing Exhibit 16, conduct a "rapid assessment" of the cost-effectiveness and achievability of ramping up its current portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and include the results of this rapid assessment in its Modified 2020 IRP. The Company will work with the DSM Advisory Group and, if desired, a contractor selected with input from the Advisory Group, in preparing this assessment. Develop and include in the Modified 2020 IRP a set of modifications to the Company's existing DSM portfolio that would achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and screen such measures for cost-effectiveness and achievability	IV.C, Appendix D

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20 (Finding of Fact 15) 91 (Ordering Paragraph 6.f)	It is reasonable to require that DESC include in its Modified 2020 IRP a DSM Action Plan that includes its plans to undertake a comprehensive evaluation of the cost-effectiveness and achievability of DSM portfolios reaching 1% and higher savings, including savings levels of 1.25%, 1.5%, 1.75% and 2%, and to work with the Advisory Group to develop and characterize these levels of DSM savings. Include in its Modified 2020 IRP action steps the Company will take to complete a comprehensive evaluation of the cost-effectiveness and achievability of DSM portfolios ranging from 1% to 2% savings, as identified in steps 3 through 4 of Hearing Exhibit 16.	IV.D, VII.E
21 (Finding of Fact 21)	The Proposed IRP does not provide sufficient information for the Commission to evaluate the plain in light of "power supply reliability." It is reasonable to require that DESC include recent generator performance and other reliability data in its Modified 2020 IRP and future IRPs. It is also reasonable to require DESC to include in its Modified 2020 IRP additional information regarding storm and hurricane-related outages and their impact on resource planning.	II.C
21-22 (Finding of Fact 23) 88 94 (Ordering Paragraph 11)	It is reasonable to require DESC to include a three-year Action Plan in its Modified 2020 IRP and in future IRPs. The three-year Action Plan should identify and describe the steps DESC will take to implement its IRP during that three-year period. This Action Plan should include a graphical representation of the planned sequence of actions. Accordingly, DESC shall include in its Modified 2020 IRP and in future IRPs a three-year Action Plan identifying and describing the steps it will take to implement its IRP during that three-year period, including but not limited to additional analyses, changes to its methodology, issuance of Requests for Proposals, modifications to its DSM portfolio, and applications for new generating facilities under the Siting Act. The Action Plan shall include a graphic representation of the sequencing of its actions. The Action Plan in the Modified 2020 IRP shall include, at a minimum, the DSM Action Plan discussed elsewhere in this Order; the Company's process for selecting a capacity expansion model, in collaboration with stakeholders; the Company's plans to conduct retirement studies required by this Order; as well as any actions related to competitive procurement of renewable energy resources that may be indicated based on the additional production cost modeling that the Commission is requiring in this Order. DESC shall include in its Modified 2020 IRP and in future IRPs a three-year Action Plan identifying and describing the steps it will take to implement its IRP during that three-year period, including but not limited to additional analyses, changes to its methodology, issuance of Requests for Proposals, modifications to its DSM portfolio, and applications for new generating facilities under the Siting Act. The Action Plan in the Modified 2020 IRP shall include, at a minimum, the DSM Action Plan discussed elsewhere in this Order; the Company's process for selecting a capacity expansion model, in collaboration with stakeholders; the Company's plans to conduct retirement studies required by this Order; as well as any actions related to competitive procurement of renewable energy resources that may be indicated based on the additional production cost modeling that the Commission is requiring in this Order.	VII
33-34 86 89 (Ordering Paragraph 6.a) 89-90 (Ordering Paragraph 6.b.i)	The Commission will therefore require DESC, in its Modified 2020 IRP, to model the additional resource plans (RP7-A and RP7-B) proposed by SCSBA Witness Sercy, and to re-model resource plan RP2 for comparison purposes. In modeling the costs of those plans, DESC must incorporate all the other modeling and other adjustments discussed elsewhere in this Order. As discussed below, the Commission will also direct DESC to model those resource plans with the cost sensitivities proposed by Mr. Sercy. Accordingly, the Commission will direct DESC to conduct additional production cost modeling and analysis, as recommended by SCSBA, on an expedited basis (within 30 days of this Order) in order to inform decisions regarding the possible conduct of near-term competitive solicitations. The modeling shall include the RP2 resource plan (as modified using the same input and methodological changes the Commission is Ordering for the Revised 2020 IRP), as well as SCSBA's proposed RP7-A and RP7-B resource plans. DESC shall model price sensitivities for flexible solar PPAs at price points of \$38.94/MWh, \$36/MWh, and \$34/MWh. For the reasons discussed in Section V.D.6, supra, that modeling shall include an assumption that the addition of solar PPAs will result in integration costs equivalent to \$0.96/MWh. That modeling shall be filed in this docket as well as for informational purposes in the pending generic competitive solicitation proceeding, Docket No. 2019-365-E. Include additional candidate resource plans, representing the near-term deployment of renewables as described in the testimony of SCSBA Witness Sercy (specifically, the resource plans identified as RP7-A and RP7-B) Use the flexible solar PPA cost assumptions recommended by SCSBA in the Rebuttal Testimony of Witness Sercy, and model 400 MW of Flexible Solar PPAs starting in 2023 with 20-year PPA prices of \$34/MWh, \$36/MWh, and \$38.94/MWh.	VI
52 90 (Ordering Paragraph 6.b.ii)	The Commission finds that in modeling the cost of battery storage PPAs in the Modified 2020 IRP, DESC shall use the NREL ATB's low storage cost case (including capital and fixed O&M costs) with the same 22% ITC safe harbor assumptions discussed above for solar PV PPAs. DESC shall also adopt Mr. Sercy's recommended approach to modeling battery storage PPA costs, as described herein. For battery storage PPAs, use the NREL ATB's low storage cost case (including capital and fixed O&M 13 costs) with the same 22% ITC safe harbor assumptions employed for solar PV PPAs.	VI.C

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53 90 (Ordering Paragraph 6.b.vi)	While the Company responded to ORS' recommendation to reassess its long-term continuing capital cost –de-escalation in its Supplemental IRP, we are persuaded by the testimony of Sierra Club Witness Stenclik that the Company implemented the two different escalation rates incorrectly which led to a spike in capital costs for both solar PV and BESS in 2031 and onwards. The Company is required to correct this error in a Modified 2020 IRP. For its long-term continuing capital cost de-escalation for both solar PV and BESS, correct its implementation of the two different escalation rates consistent with Mr. Stenclik's surrebuttal testimony.	VI.C
56 90 (Ordering Paragraph 6.b.v)	For purposes of the IRP, we agree with the recommendation of Sierra Club Witness Stenclik and ORS Witnesses Sandonato and Hayet that the Company should include in a Modified 202 IRP industry accepted ICT capital cost assumptions, such as NREL. We would also note that the Company relied on data from NREL for determining its future cost of renewable energy projects, so it should do the same for the ICT. For ICT, use industry accepted ICT capital cost assumptions, such as NREL.	VI.C
58 90 (Ordering Paragraph 6.b.iii)	In its Modified 2020 IRP, DESC shall calculate the current ELCC capacity value for solar based on the current level of operational solar on DESC's system, and DESC shall apply that value in its modeling of PV resources. Correct the incremental flexible solar PPA capacity value assumptions to reflect the ELCC value specific to the existing system penetration level of incremental flexible solar PV.	Appendix F and G
60 90 (Ordering Paragraph 6.b.iv)	Under the circumstances of this IRP, the Commission concludes that consistent with its finding in Order No. 2020-244 at 4, a solar integration cost of $0.96/MWh should be used by DESC when performing the updated resource portfolio modeling required herein, both in the Modified 2020 IRP and in the additional modeling to be produced within thirty (30) days (discussed further below). Assume integration costs of $0.96/MWh for solar PV, until an updated, Commission-approved methodology for calculating solar integration costs is available.	VI
71 90 (Ordering Paragraph 6.b.vii)	The Commission will therefore direct DESC, in the production cost modeling conducted for the Modified 2020 IRP, to use the AEO low, reference, and high gas prices described by Mr. Sercy in place of DESC's low, base, and high gas prices. Re-run its production cost modeling using the AEO low, reference, and high gas prices described by SCSBA Witness Sercy in his direct testimony, and using the AEO High CO_2 case, also as detailed in Mr. Sercy's direct testimony.	VI
81	For that reason, the Commission adopts Witness Sommer's recommendation that DESC be required to calculate the rate and bill impacts of its various portfolios in the IRP, rather than just a levelized NPV of revenue requirements. DESC must include such an evaluation in its Modified 2020 IRP and in future IRPs and IRP Updates.	VI.J
81	DESC is directed to revise its 2020 IRP to include further analysis and consideration for how state or federal environmental regulations, including the Coal Combustion Residuals rule, the Steam Electric Power Generating Effluent Guidelines and Standards, National Ambient Air Quality Standards, and current and potential future greenhouse gas-related rules, might affect DESC's generating units and resource choices.	I.C
88	In addition to the Action Plan, Dominion shall explain how the IRP is integrated into other planning at the company by subdivision, division, and department within the Company.	VIII
93-94 (Ordering Paragraph 10)	In its 2020 Modified IRP, 2021 IRP Update, and subsequent annual Updated prepared pursuant to S.C. Code Ann. § 58-37-41(D)(1), DESC shall update its planning assumptions relating to the energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, and changes to projected retirement dates of existing units.	III, VI

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Appendix C: Glossary of Terms

Table of Abbreviations			
Abbreviation	**Name**	**Abbreviation**	**Name**
ACE	Affordable Clean Energy	ICT	Internal Combustion Turbine
ATW	Ash Transport Water	kW	Kilowatt
BAA	Balancing Authority Area	kWh	Kilowatt Hour
BEV	Battery Electric Vehicles	MW	Megawatt
BSER	Best System of Emissions Reduction	MWh	Megawatt Hour
CC	Combined Cycle Power Plant	NEEP	Neighborhood Energy Efficiency Program
CO_2	Carbon Dioxide	NERC	North American Electric Reliability Corporation
DER	Distributed Energy Resource	NPV	Net Present Value
DR	Demand Response	ORS	Office of Regulatory Staff
DSM	Demand Side Management	PHEV	Plug-in Hybrid Electric Vehicles
EE	Energy Efficiency	PPA	Power Purchase Agreement
EIA	Energy Information Administration	PV	Photovoltaic
EIPC	Eastern Interconnection Planning Collaborative	SCADA	Supervisory Control and Data Acquisition
ELG	Effluent Limitation Guidelines	SEPA	Southeastern Power Administration
EPA	Environmental Protection Agency	STAP	Short-Term Action Plan
ERO	Electric Reliability Organization		
FERC	Federal Energy Regulatory Commission		
FGD	Flue Gas Desulphurization		
GWh	Gigawatt Hour		
HVAC	Heating, Ventilation, and Air Conditioning		

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Appendix D: DSM Rapid Assessment

ICF

Dominion Energy South Carolina:
Rapid Assessment in Support of a High Case Energy Efficiency Scenario for its Modified 2020 IRP

February 2021

Executive Summary

In June 2018, ICF was retained by Dominion Energy South Carolina, Inc. ("DESC") to produce a 10-year potential study focused on both Energy Efficiency ("EE") and Demand Response ("DR") measures. Based on the results of the potential study, a five-year program plan was developed for the purposes of guiding the implementation of cost-effective energy efficiency programs. DESC presented *The Dominion Energy South Carolina: 2020–2029 Achievable DSM Potential and PY10–PY14 Program Plan* ("DSM Potential Study") to the Public Service Commission of South Carolina ("Commission") for review in Docket 2019-239-E and, based on the results of the Demand Side Management ("DSM") Potential Study, requested that the Commission approve a suite of ten modified, expanded, and new DSM programs for a period of five years. In December 2019 by Order No. 2019-880, the Commission approved the proposed suite of programs.

In that same order, the Commission required DESC to recalculate avoided costs and reevaluate the approved DSM programs and measures as per the avoided cost and avoided cost methodology approved in Docket No. 2019-184-E. DESC was also ordered to file the "DSM Potential Study Avoided Cost Update" with the Commission with resulting avoided costs results and changes to its DSM programs. The details of that analysis were filed with the Commission on July 22, 2020. In summary of that analysis, 25 additional measures were found to be cost-effective, 16 of which were already included in the DSM Potential Study as they were iterations of measure bundles that were already included in the program offerings.

In Docket No. 2019-226-E, DESC included three DSM cases – Low, Medium and High – as sensitivities modeled in DESC's 2020 Integrated Resource Plan ("IRP"). Both the Low and Medium sensitivity cases were supported by the results of the DSM Potential Study. However, the High case sensitivity represented a reduction in retail sales above the potential study findings making its cost-effectiveness unknown. Among the recommendations filed in direct testimony by the Office of Regulatory Staff ("ORS") was the request that "the Company should only use DSM assumptions for its IRPs and sensitivities that it has confidence in and believes are reasonable and achievable."[1]

Through testimony in Docket No. 2019-226-E, Hearing Exhibit 16, Dr. David G. Hill identified "an action plan the Company could implement to fairly evaluate a high DSM case representing 1% or higher savings levels in an amended 2020 IRP and in future IRPs."[2]

In Docket No. 2019-226-E - Order No. 2020-832 Ordering Paragraphs 6.d. and 6.e., the Commission states that DESC shall:

d. Develop and include in the Modified 2020 IRP a set of modifications to the Company's existing DSM portfolio that would achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and screen such measures for cost-effectiveness and achievability.
e. Consistent with step 1 as identified in Hearing Exhibit 16, conduct a "rapid assessment" of the cost-effectiveness and achievability of ramping up its current portfolio to achieve at least a 1% level of savings in the years 2022, 2023, and 2024, and include the results of this rapid

[1] Docket No. 2019-226-E, Direct Testimony of Anthony M. Sandonato on behalf of the South Carolina Office of Regulatory Staff, Exhibit AMS-1, p 8
[2] Docket NO. 2019-226-E, Late Filed Exhibit of David G. Hill, Ph.D., p 1. Note: The 1% or higher savings level is based on the previous year's retail sales.

assessment in its Modified 2020 IRP. The Company will work with the DSM Advisory Group and, if desired, a contractor selected with input from the Advisory Group, in preparing this assessment.

This memo details both the process and results of the "rapid assessment" and offers DSM case levels associated with energy efficiency programs to factor into DESC's Modified 2020 IRP. This assessment also includes a reasonable, achievable and cost effective "High Case "energy efficiency forecast that incorporates several of Dr. Hill's recommendations.

In summary, when compared to the DSM portfolio that takes into account the avoided cost update, these changes result in an increase of 437,575 MWh, an increase of approximately $60 million in the 10-year potential study, and a max percent sales achievement in the 10 years of 1.03% versus 0.7% as previously identified. These results are summarized in the Appendix.

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Background and Program Analysis

When developing the approach for the "rapid assessment", ICF took a systematic approach in order to properly assess portfolio expansion options. This included identifying possible opportunities and benchmarking measures and programs, assessing the applicability and availability for participation in DESC service territory, and developing forecasts and impacts as appropriate. As part of the analysis that was performed, ICF assessed these modifications in the context of:

1. What is reasonable based on program experience
    a. Is the measure or program applicable for implementation in the DESC service area
2. What is achievable within the service territory and market acceptance
    a. Can quantifiable forecasts be recommended based on DESC program experience, outcomes of the 2019 Potential Study (including feedback from market actors), expected industry shifts (including standards), and ability to implement within the 2022, 2023, 2024 time horizon
3. Accounting for cost-effectiveness
    a. Specifically accounting for calculation of the Total Resource Cost ("TRC") test and the Utility Cost Test ("UCT")

On October 21, 2020, Dr. David G. Hill, Ph.D. late-filed an exhibit pertaining to Docket No. 2019-226-E per the request of Commissioner Thomas J. Ervin. Commissioner Ervin requested this exhibit in which an action plan would be identified that the Company could implement to fairly evaluate a demand side management case that represented 1% or higher savings levels in an amended 2020 IRP and in future IRPs. As a first step, Dr. Hill recommends that the Company conduct a "rapid assessment" of the achievability of ramping up DESC's current portfolio to achieve at least 1% annual savings in 2022, 2023, and 2024. As part of this assessment Dr. Hill recommended six (6) specific actions that could take place, including:

1. Municipal Lighting – Increasing outreach to approximately 54,000 units
2. Small Business Direct Install ("SBDI") – 25% increase in participation
3. Neighborhood Energy Efficiency Plan ("NEEP") – Double participation
4. Home Energy Reports ("HER") – move to an opt-out program in 2021
5. Residential HVAC – 25% increase focusing on electric resistance heat replacements
6. EnergyWise for your Business ("EWfYB") – 25% increase

This assessment resulted in the adoption of the recommendations made for:

- Municipal Lighting
- Neighborhood Energy Efficiency Program
- Home Energy Reports

These results were presented and discussed with the Energy Efficiency Advisory Group on January 19, 2021. After completion of this initial analysis, DESC began an assessment of all areas of expansion outside of Dr. Hill's recommendations to develop a DSM High Case scenario that meets the Commission requirements of achieving 1% of sales savings in the years 2022, 2023, and 2024. The following sections provide discussion of:

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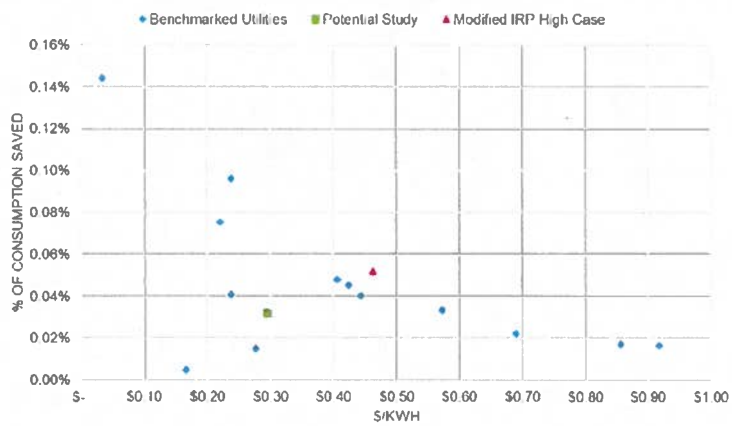
1. Programs and Measures that were assessed and included in the Modified 2020 IRP DSM High Case
2. Programs and Measures that were assessed and are NOT included in the Modified 2020 IRP DSM High Case
3. Final forecast that meets the Commission requirements for a DSM High Case achieving 1% incremental savings of sales

Programs and Measures Considered and Included in Expansion

Appliance Recycling

As part of the assessment for expansion of the Appliance Recycling program, ICF conducted benchmarking against utilities that offer identical or similar programs. Based on this benchmarking ICF determined that there is room for growth of the program in the traditional refrigerator and freezer recycling measures while also opportunity for inclusion of incentives for dehumidifier and room air conditioner recycling.

Figure 1: Appliance Recycling Benchmarking

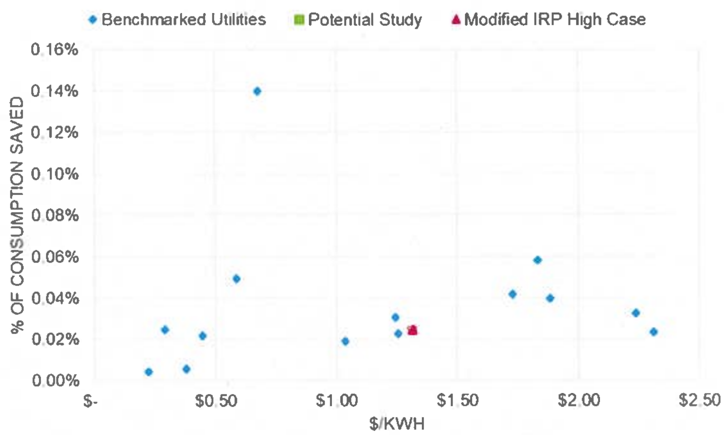


Residential HVAC

ICF conducted benchmarking for the Residential HVAC program and based on this analysis found that the current program forecasts are reasonable and achievable. Taking a deeper look at the individual measures, we concluded that there is the possibility for additional participation in the electric furnace replacement with an electric heat pump measure type.

Effective December 1, 2020, DESC began offering a new rebate ($650) for replacement of an electric furnace (heats with electric heat strips) with an EnergyStar qualified heat pump. We anticipate that the measure will be well received by both customers and contractors within our service territory. Given this, ICF expects that participation for this specific measure could be increase by 10%. Contractor training, customer education and marketing will continue to optimize the offering. Should customer and contractor participation exceed expectations, DESC will not limit participation or cap the number or rebates provided to customers.

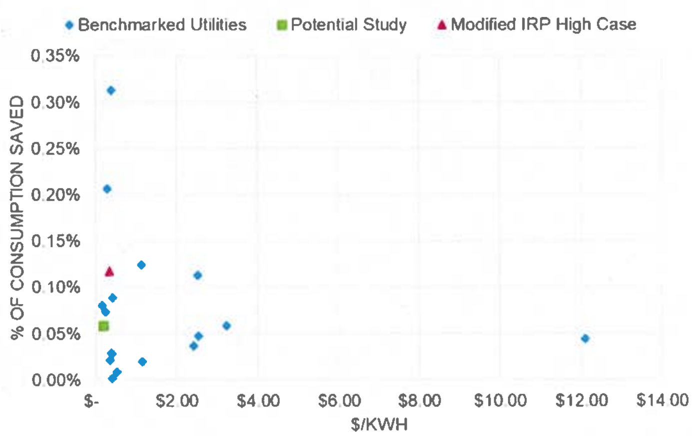
Figure 2: Residential HSVAC Benchmarking



Neighborhood Energy Efficiency Program

In the benchmarking performed for NEEP, ICF found that DESC is operating a notably cost-effective and well performing program. However, based on extensive program experience within its service territory, recently expanded poverty level guidelines and assurances by the implementation contractor of having the ability to hire and train more staff for field work, DESC believes that participation in this program could be doubled. In addition, there is opportunity for DESC to offer full cost replacements of electric furnaces with heat pumps and the replacement of inefficient refrigerators for qualifying customers.

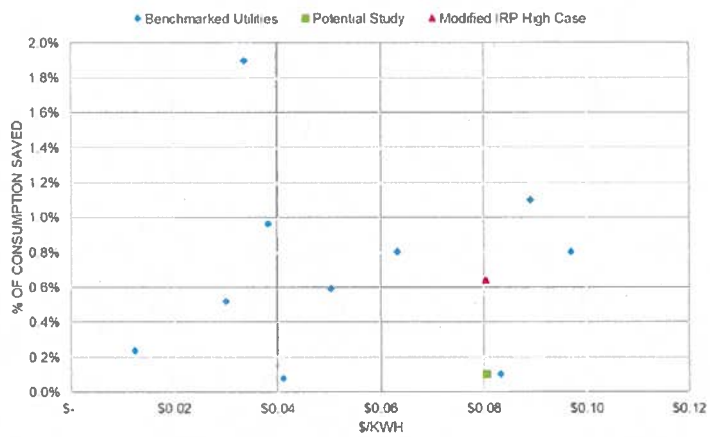
Figure 3: NEEP Benchmarking



Home Energy Reports

As part of the 2019 Potential Study, it was assumed that there would be a move from an "opt-in" HER to an "opt-out" delivery model in 2023 which would increase the participation and in turn the savings achieved in the program. DESC has already begun the move to an "opt-out" program in 2021, earlier than expected. Further, based on program benchmarking coupled this earlier transition, ICF concluded that there is additional opportunity for participation in the treatment group. Many programs have over half of their residential customer population as part of the treatment group in an HER program and revising forecasts for this program to a comparable level results in significant savings increase to the portfolio.

Figure 4: Home Energy Report Benchmarking



Municipal Lighting

In the 2019 Potential Study and Program Plan, DESC identified approximately 54,000 available lights for early retrofit replacement. However, DESC did not include the complete retrofit of all the available lights during the 5-year program plan. This was mainly due to the expectation that prices for LED fixtures would continue to fall and the future price reduction would be unworthy of incentivizing the retrofit replacements. DESC has reassessed the market for these retrofits and has concluded that pursuing all opportunities associated with this offering is in the best interest of the Company and customers.

EnergyWise for Your Business

As noted in the 2019 Potential Study, a large percentage of opt-out customers currently limits the savings potential of the EWFYB program. The distribution of customers who have opted-out of participating in the energy efficiency programs means that the possible industrial energy savings and DSM programs targeting that sector will be significantly smaller. At the time of the study, non-residential customers accounting for 84% of industrial sales and 5% of commercial sales had opted-out of participating in the programs. This large percentage of opt-out continues to limit the savings potential, measure types and participation that can be achieved. However, the 2019 Potential Study did consider additional measures, participation levels, and program types for those who have not opted-out of the programs. The additional offerings include an agricultural component and strategic energy management.

As part of an additional "gap analysis" and conducting research on other measure types that could be included as part of DESC's non-residential prescriptive program, ICF concluded that a "Cool Roofs" measure is a suitable offering for a prescriptive rebate. It is important to note that this measure could have been applied for and incentive received under the non-residential Custom track, but by offering a prescriptive incentive ICF expects increased participation as participation burdens are reduced.

During the 2019 Potential Study, DESC also considered a non-residential midstream program offering that would provide midstream distributors with incentives for both lighting and heating measures. DESC conducted workshops and received direct feedback from both heating & cooling and lighting contractors and distributors. The feedback results were not positive and indicated a lack of interest in administering or participating in midstream incentives and the offering was not included in the 5-year program plan. Based on the opt-out percentage and market insights gained, DESC does not find this recommendation to be reasonable or achievable.

Programs and Measures Considered and Not Included in Expansion

Small Business Direct Install

SBDI identifies cost-effective efficiency retrofit opportunities and provides the direct installation of measures, financial incentives, and other strategies to encourage early replacement of existing equipment with high-efficiency alternatives. Customer incentives are provided to reduce a significant portion of the cost of installing energy-efficient equipment and are based on the total installed cost of the retrofits.

As part of the 2019 Potential Study and Program Plan, the Company had taken a very aggressive path with the SBDI program by increasing participation by approximately 40% in Program Years 11 and 12. In June 2020, DESC increased the SBDI customer incentive to 90% of project costs up to $6,000 to help support the increased participation values contained in the Potential Study. As part of the rapid assessment ICF evaluated various levels of increased participation and savings and found that there is no defensible forecast of additional savings.

New Energy Efficiency Measures

As part of the analysis to assess the expansion of the current program offerings, ICF reviewed measures being offered by other utilities and included those as discussed above. Further, two specific measures were identified and ICF concluded that these were not suitable for inclusion. These include geothermal heat pumps and heat pump clothes dryers.

Geothermal heat pumps provide significant savings in the range of 1,600 kWh/year; however, they have a high cost in the range of $20,000. Based on this analysis the geothermal heat pumps measure is not cost-effective in DESC territory with a TRC of approximately 0.28.

Heat pump clothes dryers are a relatively new and advanced appliance. It uses heat pump technology to heat air through a coil, absorbs moisture from the clothes into this air, and then moves the air across an evaporator in order to remove the moisture. The air is then recycled to repeat the process. Given that this technology is relatively new, assessing the performance of this measure in DESC territory is difficult if not near impossible and no defensible achievement forecast could be derived. DESC will continue to monitor this measure for inclusion in the upcoming DSM potential study.

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New Energy Efficiency Programs

As part of the analysis to assess the expansion of the overall portfolio, ICF reviewed programs being offered by other utilities and assessed for inclusion. Specifically, ICF identified three programs and ultimately concluded that these were not suitable for inclusion. These programs include "My Energy Target", a low-to-moderate income locational based program, and a pre-pay program.

"My Energy Target" is a program that uses AMI data to create a personalized energy consumption target for specific customers during summer months. Incentives are offered for varying target levels and paid as the customer achieves that target. Currently ICF is aware of only one utility that has offered this program as a pilot, and while early results indicate it is successful, there is too little evaluation history of it for inclusion at this time. DESC will continue to monitor this program for possible inclusion in the upcoming DSM potential study.

Low-to-Moderate Income ("LMI") Locational Based Savings is a program concept that identifies groups of LMI customers at varying percentages of federal poverty level. This customer mapping is then overlaid with areas of distribution constraint and/or "resiliency areas". Such "resiliency areas" could include areas that are more prone to severe temperature swings or flooding. By identifying these target areas, targeted recruitment and higher incentives can be offered to these customers to not only reduce their energy burden but provide overall grid benefits and/or societal benefits. ICF is aware of utilities that have proposed this program but are not aware of any utility offering this program concept at this time, and as such no defensible forecast for savings achievement could be assessed. DESC will continue to monitor this program for possible inclusion in the upcoming DSM potential study.

A "pre-pay" program operates similarly to purchasing "cell phone minutes". A customer pre-pays for a certain amount of electricity in a defined time period (i.e. month) and modifies their behavior around this amount in order to not have to "purchase" more. DESC is already planning a "Pay as You Go" program and as such is not included in the rapid assessment at this time.

New Rate Based Energy Efficiency Programs

While rate-based programs have historically been used to reduce capacity needs, there is some speculation that rate-based programs could produce energy savings. ICF assessed the viability of a Peak Time Rebate and a Time-of-Use program offering to provide energy savings. As part of this assessment ICF found that because of the focus of these programs on demand savings there has been very little evaluation of the contributions such programs could make to energy savings. Based on the analysis compiled, we also believe that the energy savings that have been reported for similar programs may be encompassing other program savings too, most likely the HER program. In addition, there is also concern that such a program increases usage as customers may consume more during lower priced times. At this time, ICF concludes that there is not a defensible forecast that could be placed in the rapid assessment.

Distributed Energy Resources

Noting that the utility landscape and customers usage is rapidly changing, ICF also identified four distributed energy resources to assess. These include solar generation, off-road electrification, on-road electrification, and battery storage. Noting that none of these provide any consumption "savings", ICF concluded that they are not reasonable for this analysis.

Final Assessment Results

Based on the analysis performed as part of the rapid assessment, ICF concludes that there is a path forward for DESC to achieve 1% savings in years 2022, 2023, and 2024. These annual forecasts including costs, quantified savings (MWh), and percent of sales achievement are included in the Appendix.

Conclusions

In summary, DESC appreciates the thoughtfulness of suggestions supplied by members of DESC's Energy Efficiency Advisory Group for near term modifications to the Demand Side Management forecasts with the goal of achieving 1% savings of annual sales in the years 2022, 2023, and 2024. Based on the findings within the 2019 DSM Potential Study that have been approved by the Commission, and including the modifications described above, DESC does believe that achieving 1% savings is possible within the years 2022, 2023, and 2024. It is important to note what this evaluation of program recommendations is intended to produce. As is referenced in Commission orders, this is a "rapid assessment" of recommendations and has no intent to replicate the types of analysis that the development of a potential study would result in. As discussed previously, this evaluation sought to understand which recommendations are both reasonable and achievable, as well as identify new programs and measures that could be included in the portfolio.

In the Appendix following, ICF has provided modified total annual forecasted energy savings for the portfolio for Low, Medium, and High cases. Costs forecasts for the Medium and High cases can also be found in the Appendix. The Low Case is the DSM Potential Study minus 10% of forecast should unforeseen events occur (i.e. global pandemic, economic recession, waning of customer interest). The Medium Case is based on the Commission-approved 10-year Potential Study and the 5-year DSM Program Plan currently being offered to customers, with the addition of measures that are cost-effective after applying an updated avoided cost per Commission order. The High Case is the 10-year Potential Study with the avoided cost updates and Commission-approved 5-year DSM Program Plan plus the additional reasonable and achievable recommendations as discussed in this report.

Finally, we want to note that the percent of savings achieved is calculated based upon sales forecasts in the outer years and is in line with how the percentages were previously calculated. Should a percent of sales goal be recommended for DESC to base its program forecasting upon, ICF suggests that a "baseline year" be established that has sales that are weather normalized for achievement to be calculated against. One such methodology would be to average the 3 years of weather normalized sales prior to the program implementation cycle for which a percent reduction would be based upon.

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Appendix: Summary of Rapid Assessment Findings

Table 1: DSM Cases to be Factored into Modified 2020 IRP

MWh Savings	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Low	69,901	85,382	96,367	98,209	100,339	93,276	94,327	96,398	98,531	100,833
Medium	77,668	94,869	107,075	109,121	111,488	103,640	104,808	107,109	109,479	112,037
High	77,668	102,621	167,023	163,597	165,290	154,172	156,005	158,876	161,823	164,963

Table 2: Cost Comparisons of Medium and High Cases

Costs ($ Millions)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Low	$22.42	$27.16	$30.22	$30.32	$30.35	$24.91	$25.36	$25.82	$26.29	$26.61
Medium	$22.42	$27.16	$30.22	$30.32	$30.35	$24.91	$25.36	$25.82	$26.29	$26.61
High	$22.42	$32.32	$41.00	$39.18	$37.92	$30.49	$30.98	$31.45	$31.94	$32.45

Table 3: Percent of Previous Year Sales Reduction

Percent Achievement	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Low	0.44%	0.53%	0.60%	0.60%	0.61%	0.57%	0.57%	0.57%	0.58%	0.59%
Medium	0.49%	0.59%	0.66%	0.67%	0.68%	0.63%	0.63%	0.64%	0.65%	0.65%
High	0.49%	0.64%	1.03%	1.01%	1.01%	0.94%	0.94%	0.95%	0.95%	0.96%

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Figure 5: Increase in Savings Attribution by Program

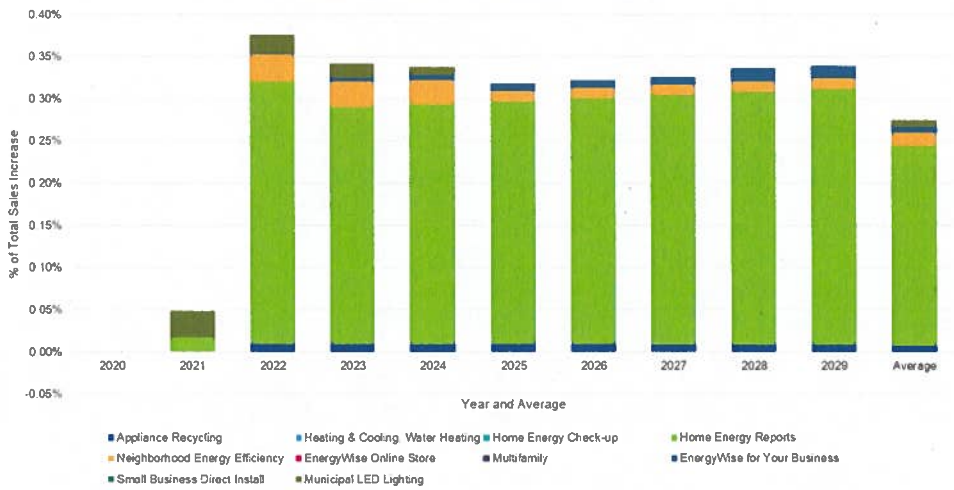


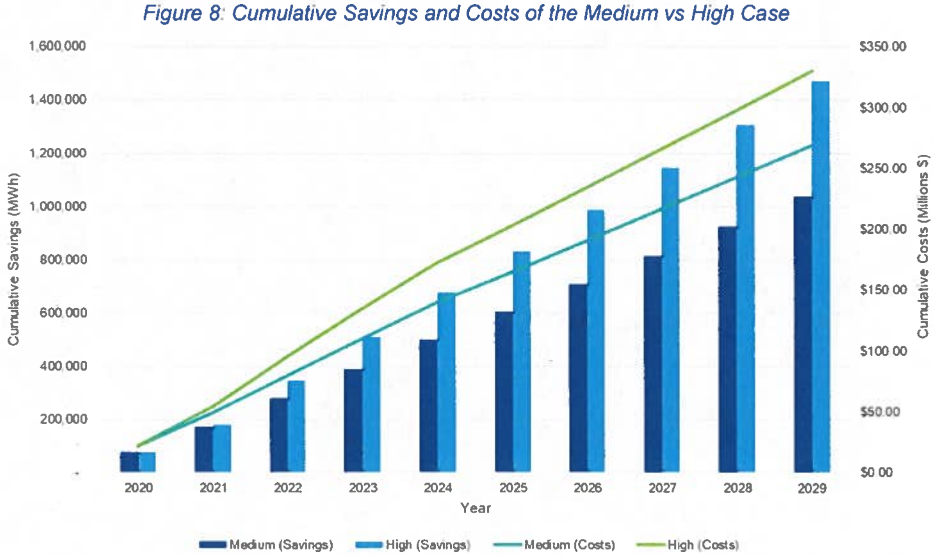
Figure 6: Quantified Increase in Savings Attribution by Program

Program	Average
Appliance Recycling	0.01%
Heating & Cooling, Water Heating	0.00%
Home Energy Check-up	0.00%
Home Energy Reports	0.24%
Neighborhood Energy Efficiency	0.02%
EnergyWise Online Store	0.00%
Multifamily	0.00%
Residential Portfolio	0.26%
EnergyWise for Your Business	0.01%
Small Business Direct Install	0.00%
Municipal LED Lighting	0.01%
C&I Portfolio	0.01%
Total Portfolio	0.27%

Figure 7: Cost Effectiveness Results of the Resulting DSM High Case

Program	TRC	UCT	RIM	PCT
Appliance Recycling	0.58	0.63	0.23	4.91
Heating & Cooling, Water Heating	0.72	0.88	0.34	1.78
Home Energy Check-up	1.00	0.84	0.31	2.40
Home Energy Reports	4.98	0.79	0.31	16.15
Neighborhood Energy Efficiency	2.67	1.07	0.26	4.25
EnergyWise Online Store	8.13	4.48	0.31	4.35
Multifamily	2.02	1.60	0.31	4.38
Residential Portfolio	1.64	0.96	0.30	3.58
EnergyWise for Your Business	1.83	2.17	0.44	2.49
Small Business Direct Install	1.85	1.74	0.39	5.45
Municipal LED Lighting	2.38	0.42	0.21	4.50
C&I Portfolio	1.89	1.76	0.41	3.38
Total Portfolio	1.82	1.41	0.37	3.42

Figure 8: Cumulative Savings and Costs of the Medium vs High Case



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Appendix E: Wateree Unit No. 2 Information

Order No. 2020-832, the Commission required the Company to provide more information on specific points related to the Wateree Unit No. 2 outage. (Order No. 2020-832 at pp. 40-41.) Responsive information to those points is as follows.

Document the $ 10 million cost limit.

Documentation is included on the following pages.

Identify the insurance company and its rating.

Dominion Energy's property insurance is managed by its Corporate Risk and Insurance group. There is not one insurer providing 100% of the insurance capacity. Rather, Dominion Energy's property insurance is purchased on a quota share basis from dozens of providers, each providing varying percentages of coverage. Generally, all carry an 'A' rating.

Identify the builder/contractor and its financial security.

Award of the prime contract for fabrication and installation of a replacement generator stator mid-section for Wateree Unit 2 has been made to Mechanical Dynamics and Analysis ("MD&A"), Ltd. MD&A is a subsidiary company of Mitsubishi Power, Ltd.

The replacement generator stator mid-section is currently being fabricated by Mitsubishi Power at Hitachi Works in Japan. MD&A has responsibility for transportation of the new equipment to the site and for its installation, as well as rewind of the existing generator rotor/field in their St. Louis repair shop.

As indicated on Mitsubishi Heavy Industry's 2020 third quarter audited financial statements (https://www.mhi.com/finance/library/result/pdf/fy20203q/financial_results.pdf), the total equity of the company was approximately $12 billion US dollars.

Identify the turbine builder and its financial security.

The Wateree Unit 2 turbine-generator set (generator S/N 170X487) was manufactured by General Electric Company (GE) and entered commercial service in 1971. The steam turbine is a GE G2-type tandem-compound, four-flow, single reheat, condensing design. The generator is a 3-phase, 60 HZ, 22 KV delta-connected generator rated at 454 MVA at 0.85 power factor and 45 psig hydrogen pressure.

The Company has no claim against General Electric at this time with respect to the Wateree Unit 2 generator-related outage.

Provide a detailed timeline for the project.

MD&A is committed to the return of Wateree Unit 2 to available status by May 15, 2022. Any failure to achieve this schedule will result in commercial penalties.

Provide a backup plan if the project fails.

In the unlikely event that the planned replacement of the Wateree Unit 2 generator stator mid-section fails to return the unit to service as planned, the Company would first exhaust all options with the current prime contractor, MD&A. One contingency could be the procurement of a suitable generator stator from a retired unit from another utility (as was initially studied in evaluating options to expeditiously and prudently repair Wateree Unit 2).

In the exceptionally unlikely event that the unit is unsuitable to be returned to service and must be retired, the Company would evaluate procurement of generation capacity through bilateral off-system capacity purchases, as required, to maintain its reserve requirements in the short-term, while evaluating options for constructing or procuring new long-term capacity to meet system needs.

Provide additional guidance regarding next steps, retirement, repairs, or the like.

DESC released the prime contract for the replacement of the Wateree Unit 2 generator stator mid-section in June 2020. The replacement stator assembly is a long-lead item that is being fabricated internationally in Japan and is expected to ship to the United States in Q4 2021, followed by shipment to the site and installation by the end of Q2 2022, returning Wateree Unit 2 to service. Fabrication of the new generator stator mid-section is well underway and the project is tracking to its original schedule and budget.

DESC will be conducting a formal retirement study for the Wateree Station (both Units 1 and 2) in 2021, as agreed to in proceedings under Docket 2019-226-E.

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RKH Specialty

UMR B0180ME1905449	180 RKH

MARKET REFORM CONTRACT

Insured	Dominion Energy, Inc.
Layer	Quota Share USD 600M
Period	From: 01 November 2019 To: 01 November 2020
Order	
No of Slips	
Hereto WTN	
Total WTN	
Sign %	
For LPSO use	
For ILU use	
For LIRMA use	

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RKH Specialty

UMR: B0180ME1905449

Risk Details:

UNIQUE MARKET REFERENCE:	B0180ME1905449
TYPE:	All Risks of Direct Physical Loss or Damage including Boiler Explosion, Machinery Breakdown, Flood, Earthquake, Named Windstorm and Business Interruption Insurance.
INSURED:	**Dominion Energy, Inc.** and Virginia Electric & Power Company and all owned, controlled, associated, affiliated, joint venture, limited liability partnerships, limited partnerships, limited liability companies or subsidiary companies or corporations as now or may hereinafter be constituted as their respective rights and interests may appear and/or as may be more fully defined in the Policy Wording.
ADDRESS OF INSURED:	120 Tredegar Street, Clearinghouse Building Richmond, VA 23219 United States of America
PERIOD:	From: 01 November 2019 To: 01 November 2020 both days at 12.01 a.m. local standard time at the address of the Insured
INTEREST:	Real and Personal Property of the Insured and Time Element coverages and all as may be more fully defined in the Policy Wording.
LIMITS OF LIABILITY:	USD 600,000,000 any one accident or occurrence Physical Damage and Business Interruption combined and in the annual aggregate separately in respect of the perils of Flood and Earthquake Subject to sub-limits as set forth in the attached Schedule of Program Sub-limits EXCESS OF Various deductible amounts as set forth in the attached Schedule of Program Deductibles
SITUATION:	Anywhere within the United States of America except worldwide in respect of Property whilst in Transit, Property in Offsite Storage and Contingent Business Interruption.
CONDITIONS:	To insure against all risks of direct physical loss or damage as per 2018-2019 RKH Specialty Policy Wording ME1805449 Notwithstanding the above, this policy shall include: All known and scheduled facilities under construction, acquisitions and divestments are to be included or removed hereunder at dates of attachment or divestment for additional or return premium calculated at the slip rate at 01 November 2019. Solar Projects under construction shall be automatically covered hereunder upon reaching substantial completion or as per project contractual requirements (if a later date than substantial completion). Projects will be declared hereunder on a quarterly basis, with the additional premium due to Insurers to be calculated at the slip rate at 01 November 2019 and pro-rated from date of attachment hereunder. Coverage in respect of Computer Systems Non Physical Damage is excluded. IUA 09-054 (FATCA) as attached. Notification of claims to: McGriff, Seibels and Williams, Inc., 2211 7th Avenue South, Birmingham, Alabama 35233, United States of America.

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Dominion Energy

Our Company

RKH Specialty

UMR: B0180ME1905449

LMA 9104 Policyholder Disclosure Notice of Terrorism Insurance Coverage.

LMA 5218 U.S. Terrorism Risk Insurance Act of 2002 as amended New & Renewal Business Endorsement as attached.

LMA 5219 U.S. Terrorism Risk Insurance Act of 2002 as amended Not Purchased Clause as attached to apply if no formal confirmation received from the Insured prior to inception.

LOSS PAYEE: Insured or Order.

NOTICES: None.

EXPRESS WARRANTIES: None other than as may be provided for in the Policy Wording.

SUBJECTIVITIES: None other than as may be provided for in the Policy Wording.

CHOICE OF LAW AND JURISDICTION:

This insurance shall be governed by and construed in accordance with the law of Virginia. Each party agrees to submit to the exclusive jurisdiction of any competent court within the United States of America.

NMA 1998 (24/04/86) Service of Suit Clause, naming:
Mendes and Mount
750 Seventh Avenue
New York
NY 10019-6829

PREMIUM:

USD <redacted> (100%) annual

Inclusive of:

USD *<redacted>* (100%) annual, in respect of TRIA as amended including non-certified terrorism

Subject to the Insured paying the additional premium charge specified herein, any terrorism exclusion or related coverage limitation contained herein shall not apply.

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PREMIUM PAYMENT TERMS: LSW 3000 Premium Payment Clause (60/15) as attached.

TAXES PAYABLE BY INSURED AND ADMINISTERED BY INSURERS: None applicable.

RECORDING, TRANSMITTING & STORING INFORMATION:

Where RKH Specialty maintains risk and claim data/information/documents RKH Specialty may hold data/information/documents electronically.

INSURER CONTRACT DOCUMENTATION:

This document details the contract terms entered into by the insurer(s), and constitutes the contract document.

This contract is subject to US state surplus lines requirements. It is the responsibility of the surplus lines broker to affix a surplus lines notice to the contract document before it is provided to the insured. In the event that the surplus lines notice is not affixed to the contract document the insured should contact the surplus lines broker.

Any further documentation changing this contract, agreed in accordance with the contract change provisions set out in this contract, shall form the evidence of such change.

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Dominion Energy

Our Company

RKH Specialty

UMR: B0180ME1905449

SCHEDULE OF PROGRAM DEDUCTIBLES (FOR 100%)
(To apply any one occurrence / accident unless otherwise stated)

Physical Damage

USD 10,000,000 any one accident or occurrence, except

USD 5,000,000 any one accident or occurrence in respect of Solar Projects

Business Interruption

60 days waiting period, except

45 days waiting period in respect of the Cove Point Import and Export operation

30 days waiting period in respect of Solar Projects

If an accident or occurrence involves more than one retention stated above, then only the largest single retention shall apply. It is understood that Physical Damage retentions apply separately to Business Interruption retentions.

7/10/19